BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 91
MISO ERAS Decision

192 FERC ¶ 61,064
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Mark C. Christie, Chairman;
David Rosner, Lindsay S. See,
and Judy W. Chang.

Midcontinent Independent System Operator, Inc. Docket No. ER25-2454-000

ORDER ACCEPTING TARIFF REVISIONS, SUBJECT TO CONDITION

(Issued July 21, 2025)

1. On June 6, 2025, Midcontinent Independent System Operator, Inc. (MISO) submitted, pursuant to section 205 of the Federal Power Act (FPA)[1] and part 35 of the Commission's regulations,[2] proposed revisions to Attachment X in the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), which contains MISO's Generator Interconnection Procedures (GIP), to establish the Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term.[3] In this order, we accept MISO's proposed Tariff revisions, subject to condition, effective August 6, 2025, as requested, as discussed below.

I. Background

2. In Order No. 2003,[4] the Commission required public utilities that own, control, or operate transmission facilities to file standard generator interconnection procedures and a standard agreement to provide interconnection service to generating facilities with a

[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. pt. 35 (2024).

[3] MISO, FERC Electric Tariff, attach. X (Generator Interconnection Procedures (GIP)) (175.0.0); *id*. app. 1 (Interconnection Request for a Generating Facility)) (57.0.0); *id*. app. 6 (Generator Interconnection Agreement (GIA)) (108.0.0) (Proposed Tariff).

[4] *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

capacity greater than 20 megawatts (MW). To this end, the Commission adopted the *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) and required all public utilities subject to Order No. 2003 to modify their tariffs to incorporate the *pro forma* LGIP and *pro forma* LGIA.[5]

3. The Commission permitted transmission providers to seek variations from the *pro forma* LGIP and *pro forma* LGIA if those variations were "consistent with or superior to" the terms of the *pro forma* LGIP and *pro forma* LGIA.[6] In addition, the Commission indicated that it would allow regional transmission organizations and independent system operators (RTO/ISO), such as MISO, to propose independent entity variations for pricing and non-pricing provisions, stating that RTOs/ISOs have different operating characteristics due to their sizes and locations and that an RTO/ISO is less likely to act in an unduly discriminatory manner than a transmission provider that is also a market participant.[7] The Commission found that RTOs/ISOs "shall therefore have greater flexibility to customize [their] interconnection procedures and agreements to fit regional needs."[8] Under the independent entity variation standard, an RTO/ISO must demonstrate that proposed deviations from the Commission's *pro forma* LGIP and *pro forma* LGIA are just and reasonable and not unduly discriminatory or preferential and accomplish the purposes of Order No. 2003.[9]

A. Overview of MISO's Generator Interconnection Process

4. Since the issuance of Order No. 2003, MISO has submitted several generator interconnection queue reform proposals. As relevant here, in January 2017, the Commission accepted MISO's proposal to implement a three-phase Definitive Planning

---

[5] Order No. 2003, 104 FERC ¶ 61,103 at PP 1-2.

[6] *Id.* PP 825-826. The Commission also permitted transmission providers to justify a variation from the *pro forma* LGIP or *pro forma* LGIA based on regional reliability requirements and required transmission providers to submit these regional reliability variations to the Commission for approval under the relevant reliability standard. *Id.* PP 824, 826.

[7] *Id.* P 827.

[8] *Id.*

[9] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 185 FERC ¶ 61,084, at P 11 (2023) (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827).

Phase (DPP) process to study interconnection requests in clusters.[10] The DPP is based on a sequential review process that facilitates the structured study and restudy of proposed generating facilities.

5. Under the current procedures, MISO conducts one system impact study in each of the three DPP phases (i.e., a preliminary system impact study in DPP Phase I, a revised system impact study in DPP Phase II, and a final system impact study in DPP Phase III) to account for withdrawn interconnection requests and to refine and update the analysis.[11] During DPP Phases II and III, MISO also conducts a facilities study.[12] DPP Phases I and II are followed by interconnection customer decision points (Decision Point I follows DPP Phase I, and Decision Point II follows DPP Phase II).[13] The decision points provide interconnection customers opportunities to evaluate study results and decide whether to proceed with or withdraw their interconnection requests. On June 26, 2025, the Commission accepted in part MISO's Order No. 2023[14] compliance filing, which maintained its DPP process as an independent entity variation.[15]

6. On January 19, 2024, the Commission issued an order rejecting MISO's proposed revisions to its GIP to implement a cap on the total MW value of interconnection requests that may be studied in a cluster, as well as exemptions to that cap (2023 MISO Queue Cap Proposal).[16] The Commission found, among other things, that "the proposal to include cap exemptions has not been shown to be consistent with the Commission's open

---

[10] *Midcontinent Indep. Sys. Operator, Inc*., 158 FERC ¶ 61,003, *order on reh'g*, 161 FERC ¶ 61,137 (2017).

[11] MISO, Tariff, attach. X (GIP) (171.0.0), §§ 7 (Definitive Planning Phase), 7.3.1 (Definitive Planning Phase I), 7.3.2 (Definitive Planning Phase II), 7.3.3 (Definitive Planning Phase III).

[12] *Id.* §§ 7 (Definitive Planning Phase), 7.3.2 (Definitive Planning Phase II), 7.3.3 (Definitive Planning Phase III).

[13] *Id.* §§ 7 (Definitive Planning Phase), 7.3.1.4 (Interconnection Customer Decision Point I), 7.3.2.4 (Interconnection Customer Decision Point II).

[14] *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

[15] *Midcontinent Indep. Sys. Operator, Inc*., 191 FERC ¶ 61,229 (2025).

[16] *Midcontinent Indep. Sys. Operator, Inc*., 186 FERC ¶ 61,054 (January 2024 Order), *order on reh'g*, 187 FERC ¶ 61,031 (2024).

access requirements"[17] because, despite the purpose of the cap being to limit the total MW studied in a queue cycle, exempted interconnection requests could enter the cycle regardless of the cap value (i.e., there was no limit to the number of exempted interconnection requests), and thus "the cap exemptions create[d] priority access to the generator interconnection process for the exempted classes of interconnection requests."[18] The Commission further stated that it had "concerns that specific exemptions have not otherwise been shown to be just and reasonable and not unduly discriminatory."[19] As an example, the Commission stated that MISO's proposal lacked "sufficient basis to conclude that the RERRA exemption will be limited to interconnection requests needed to meet state resource adequacy or reliability requirements."[20] The January 2024 Order also accepted MISO's proposed revisions to its GIP, in Docket No. ER24-340-000, to increase milestone payments, adopt an automatic withdrawal penalty, revise certain withdrawal penalty provisions, and expand site control requirements for interconnection facilities (2023 Non-Cap Queue Reform Proposal).[21]

7. On November 21, 2024, in Docket No. ER25-507-000, MISO submitted another proposal to establish a queue cap (2024 MISO Queue Cap), which the Commission accepted on January 30, 2025.[22] Unlike the 2023 MISO Queue Cap Proposal, the 2024 MISO Queue Cap established a hard limit on the total MW that could be studied in a cluster. While the 2024 MISO Queue Cap allowed for exemptions, such exemptions counted toward the hard cap limit, and the Commission determined that the proposed exemptions did not create open access concerns.[23] Unlike the 2023 MISO Queue Cap Proposal, the 2024 MISO Queue Cap did not include a RERRA exemption.

B. Initial ERAS Proposal and May 2025 Order

8. On March 17, 2025, in Docket No. ER25-1674-000, MISO submitted proposed revisions to its GIP to establish an ERAS process to provide a framework for the

---

[17] *Id.* P 170.

[18] *Id.* P 176.

[19] *Id.* P 178.

[20] *Id.* P 177 n.413.

[21] January 2024 Order, 186 FERC ¶ 61,054 at P 1.

[22] *Midcontinent Indep. Sys. Operator, Inc.*, 190 FERC ¶ 61,057 (2025) (January 2025 Order).

[23] *Id.* P 87.

expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term (Initial ERAS Proposal). On May 16, 2025, the Commission issued an order rejecting the Initial ERAS Proposal.[24]

9. In the Initial ERAS Proposal, MISO proposed to create a quarterly "first-come, first-served" serial study process to facilitate the rapid study of interconnection requests for generating resources that are committed to addressing specific, identified resource adequacy and/or reliability needs,[25] resulting in an Expedited Generator Interconnection Agreement (EGIA) within approximately 90 days of study kickoff. MISO proposed that an ERAS interconnection request must request Network Resource Interconnection Service (NRIS).[26] MISO further proposed that an ERAS interconnection request must demonstrate that it is required to meet an identified resource adequacy and/or reliability need by providing both: (1) a written notification from the RERRA, or its documented representative, where the load to be served by the generating facility is located, that certifies or determines that the generating facility should be considered for the ERAS process in order to meet a resource adequacy and/or a reliability need claimed by the RERRA, the Load Serving Entity (LSE), or the interconnection customer; and (2) an executed agreement evidencing that the ERAS project is intended to be used by the entity with the claimed resource adequacy or reliability need.[27]

10. MISO's Initial ERAS Proposal also included certain requirements and obligations for ERAS interconnection requests that would not apply to other interconnection requests, including commercial operation date requirements, greater site control requirements, a greater application fee and milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the interconnection customer withdrew its request after the EGIA was executed or filed unexecuted with the Commission.[28]

---

[24] *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,131 (2025) (May 2025 Order).

[25] *Id.* P 8.

[26] MISO's GIP defines NRIS, in relevant part, as "an Interconnection Service that allows Interconnection Customer to integrate its Generating Facility with the Transmission System in the same manner as for any Generating Facility being designated as a Network Resource. [NRIS] does not convey transmission service." MISO, Tariff, attach. X (GIP) (171.0.0), § 1 (Definitions).

[27] May 2025 Order, 191 FERC ¶ 61,131 at P 9.

[28] *Id.* P 10.

11. In the May 2025 Order, the Commission rejected MISO's Initial ERAS Proposal, finding that MISO had not shown the proposal to be just and reasonable and not unduly discriminatory or preferential.[29] The Commission agreed with MISO that ensuring reliability and resource adequacy is of critical importance. The Commission explained, however, that the Initial ERAS Proposal placed no limit on the number of projects that could be entered in the ERAS process, which could result in an ERAS queue with processing times for interconnection requests that are too lengthy to meet MISO's stated resource adequacy and reliability needs, similar to the challenges with the current DPP queue. The Commission also found that MISO had not demonstrated that the Initial ERAS Proposal will solve the identified reliability and resource adequacy needs.[30]

12. The Commission further stated that MISO's proposal to provide 14 opportunities to enter the ERAS process through 2028, "could further impede MISO's ability to process ERAS requests on an expedited basis," and would "exacerbate[] the potential for a volume of ERAS interconnection requests untethered to reliability or resource adequacy needs."[31] The Commission stated that this aspect of MISO's Initial ERAS Proposal made it difficult to determine whether the solution was narrowly tailored enough to fix the problem.

13. In addition, the Commission stated that MISO did not adequately describe how the ERAS process was sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO.[32] The Commission further stated that MISO had not demonstrated that the proposed Tariff language was tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs would be eligible for expedited study through the ERAS process.[33]

II. MISO's Filing

14. MISO explains that it is facing urgent near-term resource adequacy and reliability concerns due to load growth, generation retirement, and delays in the interconnection

---

[29] *Id.* P 197.

[30] *Id.* PP 199, 201.

[31] *Id.*

[32] *Id.* P 201.

[33] *Id.* P 202.

process[34] and that it will experience a 4.7 gigawatt (GW) shortfall by 2028 if currently planned generating facility retirements occur.[35] MISO asserts that, while it has undertaken reforms to improve queue processing, the current processing presents a barrier to developing generation that can address these near-term needs. Therefore, MISO proposes revisions to its GIP and *pro forma* Generator Interconnection Agreement (GIA) to establish a revised ERAS process, which provides for accelerated study of interconnection requests that will address urgent resource adequacy and reliability needs in the near term (i.e., within the next five years) (Revised ERAS Proposal).[36] Specifically, under the Revised ERAS Proposal, MISO proposes to create a quarterly "first-come, first-served" serial study process to facilitate the rapid study of interconnection requests for generating resources that are committed to addressing specific, identified resource adequacy and/or reliability needs,[37] resulting in an EGIA within approximately 90 days of study kickoff.

15. MISO proposes to maintain that an ERAS interconnection request must meet capacity resource requirements and therefore must request NRIS.[38] Further, MISO proposes that an ERAS interconnection request must demonstrate that it is required to meet an identified resource adequacy and/or reliability need by providing both: (1) a written verification from the RERRA, or its documented representative, where the load to be served by the generating facility is located, that determines that the generating facility

[34] Transmittal at 5.

[35] *Id.* at 6 (citing *NERC's 2024 Long-Term Reliability Assessment* (published December 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[36] *Id.* at 1. *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 1 (Definitions), 2.1 (Application of Generator Interconnection Procedures), 3.3.1 (Initiating an Interconnection Request), 3.4 (OASIS Posting), 3.9 (Expedited Resource Addition Study), 5.13 (Transition to ERAS Process), 7.2.1 (Requirements for Demonstrating Site Control for Generating Facility), 7.3.1.4 (Interconnection Decision Point I), 7.3.2.3.1 (Additional Analysis Applicable to Interconnection Requests in a JTIQ Screening Group), 11.1 (Tender), 11.2 (Negotiation), 11.2.1 (Optional negotiation period adjustment for Interconnection Facilities Study), and 11.3 (Execution and Filing); *id.* app. 1 (Interconnection Request for a Generating Facility) (56.0.0); *id.* app. 6 (GIA) (106.0.0), art. 1 (Definitions), 2.3.3, and 2.4 (Termination Costs).

[37] Transmittal at 4; Filing, Tab C (Testimony of Andrew Witmeier) at 51-52 (Witmeier Testimony).

[38] Transmittal at 36-37.

should be considered for the ERAS process in order to meet a resource adequacy and/or a reliability need that is not otherwise included in a resource plan, is claimed by the RERRA, or serves load in a retail choice state; and (2) an executed agreement evidencing that the ERAS project is intended to be used by the entity with the claimed resource adequacy or reliability need.[39]

16. MISO's proposal also maintains certain requirements and obligations on ERAS interconnection requests that would not apply to other interconnection requests, including commercial operation date requirements, greater site control requirements, a greater application fee and greater milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the interconnection customer withdraws its request after the EGIA is executed or filed unexecuted with the Commission.[40] MISO also states that the Revised ERAS Proposal contains new requirements for ERAS interconnection requests to better demonstrate the connection between a proposed generating facility and an identified resource adequacy and/or reliability need. MISO proposes to establish a cap of 68 interconnection requests that may be studied under ERAS. MISO proposes that of the 68 ERAS interconnection requests, 10 interconnection requests are carved out for independent power producers that have agreements with entities other than LSEs and eight interconnection requests are carved out for those serving retail choice loads. These requirements are described in more detail below in part IV of this order.

17. MISO requests an effective date of August 6, 2025 to ensure that the ERAS process will be in place prior to September 2, 2025, when MISO plans to start its first ERAS quarterly study period. MISO states that ERAS is meant as a short-term solution for a near-term problem, and it has written into its proposed Tariff revisions a sunset date of August 31, 2027, or the completion date of the sixty-eighth ERAS interconnection request study, whichever occurs first.[41] MISO states that it envisions ERAS as a temporary process needed until MISO is able to reduce the DPP study timeline to one year.[42]

III. Notice and Responsive Pleadings

18. Notice of the filing was published in the *Federal Register*, 90 Fed. Reg. 25042 (June 13, 2025), with interventions and protests due on or before June 16, 2025. Clean

[39] *Id.* at 9, 27-30, 51-52.

[40] *Id.* at 56.

[41] *Id.* at 38-39; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.9.

[42] Transmittal at 47.

Grid Alliance, Indicated Independent Power Producers (Indicated IPP),[43] NextEra, Public Interest Organizations (PIO),[44] and Trade Associations[45] each submitted a motion opposing the comment period of 10 days and requesting that the comment period be extended to 21 days. On June 11, 2025, the Office of the Secretary issued a notice denying the motions for extension of time.

19. Notices of intervention were filed by: the Minnesota Public Utilities Commission (Minnesota Commission); Organization of MISO States, Inc. (OMS); and the Public Utility Commission of Texas (Texas Commission).

20. Notices of intervention and comments were filed by: the Arkansas Public Service Commission (Arkansas Commission); the Illinois Commerce Commission (Illinois Commission); the Louisiana Public Service Commission and the Mississippi Public Service Commission (Louisiana and Mississippi Commissions); and the Missouri Public Service Commission (Missouri Commission).

21. A notice of intervention and limited protest was filed by the Michigan Public Service Commission (Michigan Commission).

22. Timely motions to intervene were filed by: Advanced Energy United; Alliant Energy Corporate Services, Inc. (AECS); American Clean Power Association and Clean Grid Alliance (jointly); Ameren Services Company, on behalf of Ameren Illinois Company d/b/a Ameren Illinois, Ameren Transmission Company of Illinois, and Union Electric Company d/b/a Ameren Missouri (collectively, Ameren); American Electric Power Service Corporation (AEP), on behalf of its affiliates AEP Energy Partners, Inc., AEP Indiana Michigan Transmission Company, Inc., and AEP Retail Energy Partners LLC; American Municipal Power, Inc.; Arevon; Big Rivers Electric Corporation (Big Rivers Electric); Calpine Corporation; Clean Energy Buyers Association; Clean Wisconsin; Clearway; Cleco Power LLC (Cleco); Coalition of Midwest Power Producers, Inc. (COMPP); Coalition of MISO Transmission Customers; Constellation

[43] Indicated IPPs include: Arevon Energy, Inc. (Arevon); Clearway Energy Group LLC (Clearway); Cordelio Power LP (Cordelio); EDF Renewables, Inc. (EDF); Invenergy LLC; NextEra Energy Resources, LLC (NextEra); and Pine Gate Renewables, LLC (Pine Gate).

[44] For purposes of the motion opposing the 10-day comment period, PIOs include: Clean Wisconsin; Fresh Energy; Natural Resources Defense Council; Sierra Club; and Sustainable FERC Project.

[45] Trade Associations include: American Clean Power Association; Clean Grid Alliance; Electric Power Supply Association (EPSA); Solar Energy Industries Association (SEIA); and Southern Renewable Energy Association.

Energy Generation, LLC (Constellation); Consumers Energy Company (Consumers Energy); Cooperative Energy; Cordelio; DTE Electric Company (DTE Electric); Duke Energy Indiana, LLC (Duke Energy Indiana);[46] Earthrise MISO Companies;[47] East Texas Electric Cooperative, Inc.; EDF; EPSA; Enel Green Power North America, Inc. (Enel); Entergy Services, LLC (Entergy), on behalf of the Entergy Operating Companies;[48] Eolian, LP; Fresh Energy; Indiana Office of Utility Consumer Counselor; International Transmission Company d/b/a ITC*Transmission* (ITC*Transmission*); Invenergy Renewables, LLC (Invenergy); Large Public Power Council; Midwest TDUs;[49] MISO Transmission Owners (MISO TOs);[50] MN8 Energy LLC (MN8); New Leaf Energy, Inc. (New Leaf); NextEra; Northern Indiana Public Service Company LLC (NIPSCO); Ørsted Wind Power North America LLC; Otter Tail; Pine Gate; Public Citizen, Inc.; RWE Clean

[46] Duke Energy Business Services LLC intervened on behalf of its affiliate Duke Energy Indiana.

[47] Earthrise MISO Companies include: Gibson City Energy Center, LLC; Shelby County Energy Center, LLC; and Tilton Energy LLC.

[48] The Entergy Operating Companies include: Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy New Orleans, LLC; and Entergy Texas, Inc.

[49] Midwest TDUs include: Indiana Municipal Power Agency; The Missouri Joint Municipal Electric Utility Commission d/b/a the Missouri Electric Commission; Missouri River Energy Services; and WPPI Energy.

[50] For purposes of this filing, MISO TOs include: Ameren; American Transmission Company LLC; Big Rivers Electric; Central Minnesota Municipal Power Agency; Citizens Electric Corporation; City Water, Light & Power (Springfield, IL); Cleco; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services LLC for Duke Energy Indiana; East Texas Electric Cooperative, Inc.; Entergy Operating Companies; Great River Energy; GridLiance Heartland LLC; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company d/b/a AES Indiana; ITC*Transmission*; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC (METC); MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; NIPSCO; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company (Otter Tail); Prairie Power, Inc.; Southern Illinois Power Cooperative; CenterPoint; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

Energy, LLC; SEIA; Shell Energy North America (US), L.P.; Sierra Club; Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (CenterPoint); Southern Renewable Energy Association; Southwest Power Pool, Inc. (SPP); Sustainable FERC Project and Natural Resources Defense Council (jointly); Treaty Oak Clean Energy, LLC; Union of Concerned Scientists; Vistra Corp. (Vistra); and Wisconsin Utilities.[51]

23. Timely comments were filed by: AECS; Ameren; Big Rivers Electric; CenterPoint; Consumers Energy; DTE Electric; Duke Energy Indiana; Entergy, Cleco, and Cooperative Energy (collectively, Entergy/Cleco/Cooperative Energy); EPSA; Indiana Energy Association;[52] ITC*Transmission*, METC, and ITC Midwest LLC (collectively, ITC); Midwest TDUs; MISO TOs; NIPSCO; Otter Tail; and Wisconsin Utilities.

24. Individual comments were filed by: Governor Mike Braun (Indiana Governor); Governor Mike Kehoe (Missouri Governor); Governor Jeff Landry (Louisiana Governor); Governor Tate Reeves (Mississippi Governor); Robert E. Rutkowski; and Governor Sarah Huckabee Sanders (Arkansas Governor).

25. Timely protests were filed by: Clean Energy Associations;[53] Clean Grid Alliance; COMPP; Constellation; Invenergy; MISO Independent Power Producers (MISO IPP);[54] PIOs;[55] and Vistra.

---

[51] Wisconsin Utilities include: Wisconsin Electric Power Company; Wisconsin Public Service Corporation; and Upper Michigan Energy Resources Corporation.

[52] Indiana Energy Association filed comments on behalf of AES Indiana, CenterPoint Energy Indiana, Duke Energy Indiana, and NIPSCO.

[53] Clean Energy Associations include: Advanced Energy United; American Clean Power Association; Clean Grid Alliance; SEIA; and Southern Renewable Energy Association.

[54] MISO IPPs include: Arevon; Clearway; Cordelio; EDF; EDP Renewables North America, LLC; Enel; Invenergy LLC; MN8; New Leaf; NextEra; and Pine Gate.

[55] For purposes of the protest, PIOs include: Clean Wisconsin, Fresh Energy, Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists.

26. On June 20, 2025, MISO filed a motion for leave to answer and answer (MISO Answer).[56] On June 26, 2025, MISO IPPs submitted an answer to the MISO Answer. On June 27, 2025, Clean Energy Associations and Clean Grid Alliance each submitted answers to the MISO Answer.

27. On June 23, 2025, the Texas Commission filed comments and a motion for leave to submit comments out-of-time.

28. On July 1, 2025, MISO filed a motion for leave to file supplemental answer and answer (MISO Supplemental Answer). On July 2, 2025, Vistra filed a motion for leave to respond and response to the MISO Supplemental Answer. On July 3, 2025, Clean Grid Alliance filed a motion for leave to answer and answer to the MISO Supplemental Answer. On July 7, 2025, PIOs filed a motion for leave to answer and answer. On July 9, 2025, Michigan Commission filed a motion for leave to answer and answer to the MISO Answer and MISO Supplemental Answer. On July 11, 2025, MISO filed a motion for leave to file a second supplemental answer and answer (MISO Second Supplemental Answer). On July 15, 2025, Invenergy filed a motion for leave to answer and answer to the MISO Supplemental Answer. On July 15, 2025, Clean Grid Alliance filed a motion for leave to answer and answer to apprise the Commission of new information.

IV. Discussion

A. Procedural Matters

29. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2024), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.[57]

30. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2024), prohibits answers to a protest unless otherwise ordered by the decisional authority. We accept the answers filed in this proceeding because they have provided information that assisted us in our decision-making process.

---

[56] MISO attaches its previous transmittal letter, answers, and supporting testimonies from the Initial ERAS Proposal filing in Docket No. ER25-1674-000 as a supplement to its answer. *See* MISO Answer at 4, Tab B.

[57] Entities that filed comments or protests but did not file a notice of intervention or motion to intervene are not parties to this proceeding. *See* 18 C.F.R. § 385.211(a)(2) (2024) ("The filing of a protest does not make the protestant a party to the proceeding.").

B. Substantive Matters

31. As discussed below, we find that MISO's proposed Tariff revisions implementing the Revised ERAS Proposal are just and reasonable and not unduly discriminatory or preferential, and we accept the Tariff revisions, subject to condition, effective August 6, 2025, as requested.[58] We also find that MISO's proposed Tariff revisions accomplish the purposes of the Commission's final rules on generator interconnection, including Order Nos. 2003 and 2023, by helping to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.[59] Therefore, we find that MISO's proposed Tariff revisions meet the independent entity variation standard. Moreover, although several commenters argue for modifications to the Revised ERAS Proposal or suggest alternative solutions for addressing MISO's near-term resource adequacy and reliability needs, the Commission need only determine, under FPA section 205, whether the proposed filing is just and reasonable; the Commission is not obligated to consider whether the proposal is more or less reasonable than other alternatives.[60] We discuss the Revised ERAS Proposal in detail below.

[58] *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017) (discussing the Commission's authority to propose modifications to a utility's FPA section 205 rate proposal).

[59] Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827; Order No. 2023, 184 FERC ¶ 61,054 at P 1.

[60] *See, e.g.*, *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (*Cities of Bethany*) (when determining whether a rate was just and reasonable, the Commission properly did not consider "whether a proposed rate schedule is more or less reasonable than alternative rate designs"). Thus, having found MISO's proposal just and reasonable, we need not consider alternative proposals.

1. Resource Adequacy Concerns

a. MISO's Filing

i. Resource Adequacy Concerns

32. MISO states that, as demonstrated by its Reliability Imperative Report,[61] the 2024 OMS-MISO Survey,[62] and the North American Electric Reliability Corporation (NERC) 2024 Long-Term Reliability Assessment,[63] MISO is facing urgent near-term resource adequacy and reliability concerns.[64] MISO states that its resource adequacy concerns are driven by unexpected significant load growth from large data center development, accelerated retirements of baseload generation, increased manufacturing, queue and supply chain delays, and permitting and financing issues. MISO also anticipates long-term load growth driven by increased cooling demands, electric vehicles, and cryptocurrency.[65] MISO states that its Futures Reports[66] have demonstrated the need for

[61] MISO, *MISO's Response to the Reliability Imperative*, Executive Summary 1 (updated Feb. 2024) (Reliability Imperative Report), https://cdn.misoenergy.org/Executive%20Summary%202024%20Reliability%20Imperative%20report%20Feb.%2021%20Final631825.pdf.

[62] OMS and MISO, *2024 OMS-MISO Survey Results* 2 (2024) (2024 OMS-MISO Survey) https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[63] NERC, *2024 Long-Term Reliability Assessment* (2024) (NERC 2024 Long-Term Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[64] Transmittal at 13-16.

[65] *Id.* at 6.

[66] MISO's Futures Reports include forecasted scenarios designed to capture a range of system conditions over a 20-year planning horizon. The Futures Reports provide the foundation for MISO's local and regional long-term planning and represent "multiple possibilities for future system growth, fuel availability, market conditions, and regulatory environments." *See* MISO, *Future Plan Scenarios* (Apr. 15, 2025) https://www.misoenergy.org/planning/futures-development/.

MISO to take immediate action "to add almost twice the generation that MISO currently has online" over 20 years as a result of this unprecedented load growth.[67]

33. MISO states that the recently published 2025 OMS-MISO Survey[68] found that the near-term resource adequacy risks and uncertainties that MISO faces are intensifying.[69] MISO further states that the 2025 OMS-MISO Survey indicates that at least 3.1 GW of new resources are needed by the summer of 2026/2027 to avoid a resource deficit, and that future years will have greater needs.[70] MISO states that NERC's 2025 Summer Reliability Assessment identified MISO as having an elevated potential for insufficient operating reserves in above normal conditions for the 2025 summer season.[71] MISO adds that, in comments submitted to the Commission's June 2025 Technical Conference[72] regarding resource adequacy, it explained that, despite the rapid growth of wind and solar resources in its region, by 2042, MISO could face a net decline of about 32 GW in available electricity below the 2022 baseline due to the operating characteristics of these

[67] Transmittal at 14 (citing MISO, *MISO Futures Report Series 1A*, at 2 (Nov. 1, 2023) (MISO Futures Report), at Series1A_Futures_Report630735.pdf). MISO predicts an increase of generating capacity from 732 terawatt hours in 2022 to 1,395 terawatt hours in 2042 under the Future 3A scenario. MISO Futures Report at 3.

[68] OMS and MISO, *2025 OMS-MISO Resource Adequacy Survey Results* (2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf

[69] Transmittal at 6 (citing OMS and MISO, *2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet (2025 OMS-MISO Survey Fact Sheet), 20 https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf).

[70] *Id.* at 15 (citing 2025 OMS-MISO Survey Fact Sheet).

[71] *Id.* at 16.

[72] Technical Conference, *Meeting the Challenge of Resource Adequacy in RTO and ISO Regions*, Docket No. AD25-7-000 (June 4-5, 2025) (June 2025 Technical Conference) (Day 1 https://www.ferc.gov/news-events/events/day-1-commissioner-led-technical-conference-regarding-challenge-resource) (Day 2 https://www.ferc.gov/news-events/events/day-2-commissioner-led-technical-conference-regarding-challenge-resource).

resources.[73] MISO explains that it also highlighted projections that peak load in the region is expected to grow at a 1.6% compound annual growth rate and therefore threatens to outpace the addition of new generating facilities if urgent action is not taken.

34. MISO explains that it has pursued numerous avenues to address its near-term resource adequacy issues, including improving the GIP, implementing a queue cap, and making other queue improvements; however, these updates are unable to address or fill the identified near-term resource gap.[74] MISO adds that the recent queue improvements (i.e., those for increased milestone payments, site control requirements, withdrawal penalties, and the queue cap) are focused on long-term improvements to MISO's queue, and they will not be sufficient to address near-term resource adequacy needs.[75] MISO also asserts that, while interconnection customers can use provisional GIAs to achieve timely interconnection, that process is insufficient to address the need that MISO is facing, both in terms of scale and time frame.[76] MISO states that provisional interconnection service only provides for limited operation and is conditional on DPP studies for full deliverability. MISO states that DPP studies may not be available to recognize the new capacity and may still take years to finalize. MISO further notes that there may be risks associated with having a provisional GIA if the interconnection request is dependent on other interconnection requests in the queue, which may never reach commercial operation due to a lack of an off-taker or load to serve.[77] MISO states that some of the benefits of a provisional GIA are incorporated into ERAS, including increased financial commitments and an expedited timeline.[78] Finally, MISO asserts that only the proposed ERAS process will result in an EGIA that identifies all network upgrades on the MISO transmission system that are necessary to provide deliverability across the transmission system.

---

[73] Transmittal at 15 (citing Comments of Todd Ramey, MISO, June 2025 Technical Conference, at 2 (filed May 28, 2025)). *See also* MISO Futures Report at 19.

[74] Transmittal at 36.

[75] *Id.* at 46 n.202.

[76] Witmeier Testimony at 19.

[77] *Id.* at 19-20.

[78] *Id.* at 20.

ii. Revised ERAS Proposal

35. MISO states that ERAS was developed in coordination with its stakeholders to address resource adequacy and reliability needs.[79] MISO further states that because its region is largely comprised of vertically integrated utilities, which are responsible for serving load within their service territories, MISO must partner with the states, their RERRAs, and LSEs to provide a way for the generation necessary for resource adequacy or reliability to be completed quickly.[80] MISO further explains that to incorporate the important jurisdictional interplay among the role of states, other RERRAs, and the Commission, the states in MISO have independent authority for resource adequacy. Due to this, MISO states that its ERAS proposal provides a vehicle for RERRAs to verify to MISO that there is a valid, new incremental load addition not identified in other resource plans or that the proposed generating facility will address an identified resource adequacy deficiency (RERRA verification).[81] MISO states that, following the May 2025 Order, it worked with stakeholders to address concerns about ERAS implementation and to address the Commission's guidance, which has resulted in the Revised ERAS Proposal.[82]

36. MISO proposes various eligibility requirements for interconnection requests seeking interconnection service through ERAS that must be met at the time of an application submission. MISO asserts that the proposed eligibility requirements reflect stakeholder feedback and additional analysis to ensure that a project could efficiently move through the study process while still being considered ready to commence construction, or "shovel ready."[83] MISO proposes the following eligibility requirements for an ERAS interconnection request:[84]

a. New capacity requesting NRIS service must identify the claimed resource adequacy and/or reliability need for which the interconnection request is being submitted and must include: (1) the location of any load to be served (e.g., county and state, electrical bus location(s), and the local resource

---

[79] Transmittal at 18-19.

[80] *Id.* at 13.

[81] *Id.* at 9.

[82] *Id.* at 25.

[83] Witmeier Testimony at 40.

[84] *Id.* at 40-41; Transmittal at 8, 36-39.

zone[85]) because a generating facility must be in the same local resource zone as the load to be served unless the identified need is included in a resource filing made to the RERRA; and (2) the peak demand for electricity expected over any one-hour period in MWs (the amount of interconnection service requested must not exceed 150% of the identified MW need).

b. Demonstration of a resource adequacy need through each of the following:

    i. A written verification from the RERRA that either:

        1. The new, incremental load addition is valid and not otherwise included in a resource plan or other process under the purview of the RERRA;

        2. The generating facility will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer and can be supported by a range of documentation; or

        3. For a generating facility that will address a resource adequacy deficiency and serves retail choice load or a retail choice state (i.e., Illinois or Michigan), the interconnection customer will not be required to provide a RERRA verification, but the RERRA will have an opportunity to contest the interconnection request's inclusion in ERAS; and

    ii. An executed agreement evidencing that the proposed generating facility is intended to be used by the entity with the claimed resource adequacy or reliability need.

c. A non-refundable deposit (D1) of $100,000 and a refundable milestone payment (M2) of $24,000 per MW.

d. 100% site control for both the generator and interconnection customer's interconnection facilities.

[85] Local Resource Zone is proposed to mean "a geographic area within the Transmission Provider Region that is prescribed by the Transmission Provider, based upon the criteria in Section 68A.3, to address congestion that limits Planning Resource deliverability." MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 1 (Definitions).

e. A requested commercial operation date that is no more than three years from the date of submission of an interconnection request, unless the interconnection request is deferred to a later ERAS quarterly study period.

37. MISO states that, in response to the Commission's findings in the May 2025 Order, it proposes requirements for an ERAS interconnection request to be located in the same Local Resource Zone as the resource adequacy or reliability need that it will address.[86] MISO states that adding this requirement better establishes a nexus between the load need and the ERAS interconnection request. MISO asserts that including this requirement will ensure that the proposed generating facility supports Local Clearing Requirements, which is the minimum amount of seasonal accredited capacity for a Local Resource Zone that is required to meet its seasonal loss of load expectation,[87] and will prevent the proposed generating facility from driving import or export concerns. MISO further asserts that requiring the interconnection request to serve a local load will negate the need for transmission investment, reduce import needs from other Local Resource Zones, and remove price divergences between load and generation.[88] MISO states that it will allow an ERAS interconnection request to be located in a different Local Resource Zone than the load it will address if the ERAS interconnection customer can demonstrate that the use of the proposed ERAS generating facility was included in a resource filing or other submission made to the RERRA.[89]

38. MISO explains that, under the current DPP process, an interconnection request may not become commercially operational for up to 11 years after the initial submission.[90] MISO argues that given the urgent near-term resource adequacy needs in

---

[86] Transmittal at 32.

[87] MISO defines Local Clearing Requirements as "The minimum amount of Seasonal Accredited Capacity for [a local resource zone] that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such [local resource zone] and accounting for controllable exports." *See* MISO, FERC Electric Tariff, § II, Module A, § 1 (Definitions-L) (47.0.0).

[88] Witmeier Testimony at 61.

[89] Transmittal at 33.

[90] Witmeier Testimony at 47. Specifically, Mr. Witmeier testifies that the maximum of 11 years can occur because: (1) a DPP interconnection customer may request a commercial operation date up to five years from the submission of the interconnection request; (2) during GIA negotiations, the commercial operation date may be extended up to three years based on specific circumstances set forth in GIP

its region, another mechanism is needed to ensure that ERAS generating facilities come online as soon as possible. MISO states that ERAS generating facilities will continue to have the additional three-year grace period from the commercial operation date listed in Appendix B of the EGIA to become commercially operational that is currently provided to interconnection customers under MISO's *pro forma* GIA.[91] MISO asserts that, in conjunction with the other eligibility requirements, the commercial operation date requirements will ensure that only "shovel ready" projects are submitted.[92]

b. Responsive Pleadings

i. Comments in Support

39. The Arkansas Governor, Indiana Governor, Louisiana Governor, Mississippi Governor, and Missouri Governor submitted comments in support of MISO's filing as a necessary temporary measure to address resource adequacy concerns. In their respective comments, the Governors cite concerns over resource adequacy that they believe the Revised ERAS Proposal will address, including unprecedented load growth, accelerated resource retirements, and delays in new resource additions.[93]

40. Several commenters assert that ERAS is necessary to address near-term resource adequacy needs in the MISO footprint.[94] In particular, several commenters argue that the

---

section 4.4.4; and (3) MISO's *pro forma* GIA permits a three-year grace period for generating facilities to achieve commercial operation. *Id.*

[91] Transmittal at 50; Witmeier Testimony at 47. The proposed GIP states that the EGIA "shall take the form of MISO's *pro forma* GIA modified for the [ERAS]." MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 1 (Definitions).

[92] Witmeier Testimony at 31.

[93] Arkansas Governor Comments at 1; Indiana Governor Comments at 1; Louisiana Governor Comments at 1; Mississippi Governor Comments at 1; Missouri Governor Comments at 1.

[94] AECS Comments at 4; Ameren Comments at 1, 3; Arkansas Commission Comments at 3; Big Rivers Electric Comments at 3; CenterPoint Comments at 1, 4; Consumers Energy Comments at 2-3; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3; Wisconsin Utilities Comments at 4; Texas Commission Comments at 13.

accelerated review of urgently needed, "shovel ready" projects will help alleviate near-term resource adequacy needs.[95]

41. Several commenters cite concerns about the ability of MISO's DPP process to effectively meet resource adequacy needs and claim that ERAS provides an alternative mechanism to meet such needs.[96] Illinois Commission asserts that these queue problems will likely be compounded by rapid new load growth, especially resulting from the development of data centers throughout the region.[97]

42. Several commenters state that there is an urgent need to address resource adequacy and reliability challenges due to rapid load growth and that the ERAS process is a measure to address such large load growth.[98] More specifically, Big Rivers Electric and MISO TOs cite concerns over resource adequacy driven by a combination of electrification, a resurgence in manufacturing, rapidly growing demand from energy-intensive data centers, accelerated generating facility retirement, and a growing shift toward low or zero-carbon technologies.[99] MISO TOs and the Missouri Commission also note that ERAS can help address resource adequacy needs related to accelerated retirements.[100] Several commenters also state that they expect significant increases in demand on MISO's transmission system because of potential state and

[95] AECS Comments at 4; Big Rivers Electric Comments at 3; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3.

[96] AECS Comments at 2-3; Ameren Comments at 2; CenterPoint Comments at 4; Entergy/Cleco/Cooperative Energy Comments at 7-8; Illinois Commission Comments at 6; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; Otter Tail Comments at 4.

[97] Illinois Commission Comments at 6-7.

[98] AECS Comments at 2-3; Ameren Comments at 1, 3-4; CenterPoint Comments at 4; Entergy/Cleco/Cooperative Energy Comments at 7-8; Louisiana and Mississippi Commissions Comments at 5; Missouri Commission Comments at 3.

[99] Big Rivers Electric Comments at 2; MISO TOs Comments at 12.

[100] MISO TOs Comments at 12; Missouri Commission Comments at 3.

regional economic growth opportunities in the form of large-scale industrial, manufacturing, and technology-driven projects.[101]

43. ITC and NIPSCO cite to expected capacity shortfalls predicted in the OMS-MISO Survey and the NERC Long-Term Reliability Assessment and Summer Reliability Assessment as evidence that MISO is facing significant resource adequacy risks in the near-term and as justification for the Revised ERAS Proposal. MISO TOs also cite to the OMS-MISO Survey's findings that at least 3.1 GW of additional capacity beyond committed capacity will be needed to meet the projected planning reserve margin forecast.[102] ITC also cites rising summer temperatures as a concern for reliability.[103]

44. DTE Electric asserts that MISO's Revised ERAS Proposal is a reasonable, well-intentioned resource adequacy stop-gap measure designed to shore up emergent needs across the MISO footprint.[104] Furthermore, DTE Electric asserts that this proactive planning measure is just and reasonable and will serve MISO's footprint effectively and efficiently in the near term because it is limited, flexible, and transparent.

45. The Indiana Energy Association argues that the Revised ERAS Proposal is a necessary and balanced approach to meeting the resource adequacy challenges of growing complexity in the energy landscape and ensuring resources are available to meet immediate and future demand.[105]

46. CenterPoint argues that the Revised ERAS Proposal provides a reasonable and appropriate tool to address potential unprecedented customer demand growth, the need to replace retired and retiring generation resources in a manner that does not compromise resource adequacy and reliability on the MISO transmission system, and existing delays and bottlenecks in MISO's current interconnection study process caused by an unprecedented number of interconnection requests.[106] Additionally, CenterPoint asserts that MISO's Revised ERAS Proposal is intentionally designed with significant

---

[101] CenterPoint Comments at 4-5; Louisiana and Mississippi Commissions Comments at 5; NIPSCO Comments at 4.

[102] MISO TOs Comments at 12.

[103] ITC Comments at 4; NIPSCO Comments at 3.

[104] DTE Electric Comments at 4.

[105] Indiana Energy Association Comments at 2.

[106] CenterPoint Comments at 6-7.

safeguards to allow ERAS to meet urgently needed resource adequacy and reliability needs while preventing abuse of the ERAS process simply to avoid MISO's DPP.

47. Although Vistra and Michigan Commission filed protests to the Revised ERAS Proposal, they agree with MISO that there are urgent resource adequacy needs in MISO's footprint and generally agree that has MISO has made a good faith effort to create a solution.[107] Michigan Commission asserts that the Revised ERAS Proposal appropriately narrows the ERAS framework to address the Commission's concerns by requiring the identification of a specific load addition or resource adequacy deficiency.[108]

ii. Protests

(a) MISO's Identified Need

48. Several protesters argue that the studies that MISO relies on overstate the short-term risks and ignore near-term solutions in the existing queue, such as existing interconnection requests with signed GIAs or interconnection requests that can use the provisional GIA process.[109] Clean Energy Associations argue that MISO's reliance on the 2025 OMS-MISO Survey is flawed, similar to the Initial ERAS Proposal's reliance on the 2024 OMS-MISO Survey, which included an alternate projection that showed a surplus of 2.9 GW spring capacity in the 2025-2026 planning year.[110] Clean Energy Associations assert that the 2025 OMS-MISO Survey projects that MISO may need 3.1 GW of new resources by 2026/2027 and that MISO's queue and market reforms,

[107] Vistra Protest at 5, 7; Michigan Commission Protest at 7.

[108] Michigan Commission Protest at 7 (citing Transmittal at 27-30).

[109] Clean Energy Associations Protest at 24; Clean Grid Alliance Protest at 9, 34-35; PIOs Protest at 29. *See also* Clean Energy Associations Protest, Ex. A; Clean Energy Associations Protest, Docket No. ER25-1674-000, at 48 (filed Apr. 7, 2025) (Clean Energy Associations Docket No. ER25-1674 Protest); MISO IPPs Protest, attach. A, MISO Independent Power Producers Protest, Docket No. ER25-1674-000, at 3-5, 26-29 (filed Apr. 7, 2025) (MISO IPPs Docket No. ER25-1674 Protest); MISO IPPs Protest, attach. B; NextEra Energy Resources, LLC Protest, Docket No. ER25-1674-000 (filed Apr. 7, 2025) (NextEra Docket No. ER25-1674 Protest; NextEra Docket No. ER25-2674 Protest at Ex. A-1, The Brattle Group Report, at 14-15 (2025 Brattle Group Report); PIOs Protest, attach. A, Public Interest Organizations Protest, Docket No. ER25-1674-000, at 28-35 (filed June 16, 2025) (PIOs Docket No. ER25-1674 Protest).

[110] Clean Energy Associations Protest at 25-26 (citing 2024 OMS-MISO Survey at 21).

improved resource deployment timelines, and other initiatives will help MISO maintain resource adequacy through 2031.[111] Clean Energy Associations further assert that the 2025 OMS-MISO Survey used new projections that showed a potential surplus between 1.4-6.1 GW in accredited capacity against the planning reserve margin requirement for both the winter and summer seasons, which further suggests that LSEs may have adequate resources to meet load reserve requirements in each zone over a five-year horizon.[112] Clean Energy Associations contend that the 2025 OMS-MISO Survey demonstrates that MISO's current trajectory can maintain resource adequacy and can achieve surplus capacity without ERAS.[113] Clean Grid Alliance also argues that MISO's reference to its own reports and comments in the June 2025 Technical Conference are insufficient to support its Revised ERAS Proposal.[114]

49. Several protesters argue that MISO's independent market monitor (IMM) has also affirmed their concerns that MISO's near-term resource adequacy needs are overstated.[115] Clean Energy Associations assert that the IMM stated that MISO is more than resource adequate going into the summer of 2025 and does not have substantial concerns about the MISO region in the near term.[116] Clean Grid Alliance further points out that the IMM stated that MISO's risks are "not nearly as daunting as portrayed by MISO planning reports."[117] Clean Energy Associations and PIOs further state that the IMM found that MISO planning reports and the NERC 2024 Long-Term Reliability Assessment significantly understate available capacity by failing to fully account for demand response, behind-the-meter generation, and firm capacity imports – where MISO has more than 8 GW of underrecognized capability.[118] PIOs add that MISO's reliance on the Commission's 2025 Summer Energy Market and Electric Reliability Assessment, as well

---

[111] *Id.* at 26 (citing 2025 OMS-MISO Survey at 2).

[112] *Id.* (citing 2025 OMS-MISO Survey at 7, 9).

[113] *Id.* at 26-27.

[114] Clean Grid Alliance Protest at 7-8.

[115] *Id.* at 8; Clean Energy Associations Protest at 27-29; PIOs Protest at 27-29.

[116] Clean Energy Associations Protest at 27 (citing Comments of David B. Patton, Ph.D., MISO Independent Market Monitor, June 2025 Technical Conference, at 2 (filed May 28, 2025) (Patton Technical Conference Comments)).

[117] Clean Grid Alliance Protest at 8.

[118] Clean Energy Associations Protest at 27-28 (citing Patton Technical Conference Comments at 2); PIOs Protest at 28 (citing same).

as the 2025 OMS-MISO Survey, are vulnerable to the same flaws pointed out by the IMM because such reports are based largely on the flawed NERC 2024 Long-Term Reliability Assessment.[119] PIOs also contend that MISO leans on historical interconnection rates, which do not reflect the various queue reforms the Commission has recently approved for MISO.

50. Several protesters argue that in analyzing near-term resource adequacy needs, MISO fails to consider its existing DPP, which they believe are adequate to meet MISO's near-term resource adequacy and reliability concerns.[120] Specifically, protesters aver that MISO ignores the 56 GW of generation in the DPP queue with GIAs, which are expected to come online before ERAS interconnection requests.[121] Additionally, PIOs assert that MISO fails to recognize that existing DPP interconnection requests may be able to meet its resource adequacy and reliability needs. PIOs claim that even if only 21% of the current DPP interconnection requests reach GIAs, then more than 64 GW of new capacity would have signed GIAs before ERAS is complete.[122] Protesters also point to MISO's existing provisional GIA process,[123] as well as its surplus interconnection and replacement generating facility processes,[124] as alternative processes that will help MISO meet its resource adequacy needs, which MISO fails to take into consideration. Clean Grid Alliance and PIOs also contend that MISO has demonstrated through its new automation software, Pearl Street's Suite of Unified Grid Analysis and Renewables (SUGAR), that the amount of time for an interconnection request to receive a GIA has been reduced to months, which undermines MISO's claims regarding the timing of DPP interconnection requests.[125]

51. Protesters therefore assert that MISO's capacity needs can be addressed by fully leveraging the resources already in the queue, improving interconnection timelines, and

---

[119] PIOs Protest at 28 (citing, among others, FERC, *Summer Energy Market and Electric Reliability Assessment* (May 15, 2025), https://www ferc.gov/newsevents/news/ferc-releases2025-summer-assessment).

[120] Clean Energy Associations Docket No. ER25-1674 Protest at 50; NextEra Docket No. ER25-1674 Protest at 5.

[121] Clean Grid Alliance Protest at 9; PIOs Docket No. ER25-1674 Protest at 29-32.

[122] PIOs Protest at 31.

[123] Clean Grid Alliance Protest at 5-6.

[124] PIOs Protest at 29.

[125] *Id.* at 32; Clean Grid Alliance Protest at 9.

prioritizing surplus projects already in the interconnection queue that have on-shored their supply chains, making the ERAS proposal unnecessary.[126] Relatedly, Illinois Commission states that MISO should focus on improving the effectiveness and expeditiousness of the DPP queue, and ERAS should not be allowed to evolve into a second, parallel interconnection queue.[127]

52. Constellation asserts that the Revised ERAS Proposal does not address the Commission's concerns that ERAS is not narrowly tailored to only include interconnection requests capable of addressing identified near-term resource adequacy or reliability needs.[128]

(b) Commercial Operation Date

53. Clean Energy Associations assert that the Revised ERAS Proposal is not sufficiently tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs are eligible because of the commercial operation date.[129] Clean Energy Associations argue that the Revised ERAS Proposal does not address near-term issues because: (1) the requirement that the commercial operation date be achieved within three years can be extended if the interconnection request is deferred to a later quarterly study period, and (2) the three-year grace period further extends the commercial operation deadline. Clean Energy Associations thus assert that ERAS interconnection requests may come online as late as 2033. In response to MISO's contention that the commercial operation date provisions are necessary to account for delays outside of MISO's control, Clean Energy Associations assert that MISO has failed to tailor the aspects of its proposal that are within its control, such as using an ongoing quarterly study process rather than a one-time study.[130]

---

[126] Clean Energy Associations Protest at 28; Clean Grid Alliance Protest at 3, 9, 34, 41; PIOs Protest at 29-32.

[127] Illinois Commission Comments at 7.

[128] Constellation Protest at 2-4.

[129] Clean Energy Associations Protest at 9.

[130] *Id.* at 9-10 (citing Transmittal at 13, 36).

54. Several protesters contend that the problem is the supply chain and not MISO's DPP, because all interconnection customers rely on the same supply chains.[131] Clean Grid Alliance further contends that these universal supply chain issues are evidenced by MISO's commercial operation date blanket waiver filed at the Commission in recent years.[132] These protesters argue that ERAS interconnection requests may still face these challenges and may not achieve commercial operation any faster than DPP interconnection requests.[133] According to Clean Energy Associations, the ERAS process may compound these issues for DPP interconnection customers if the ERAS interconnection customers deplete existing resources.[134] Clean Energy Associations assert that, while these delays may be beyond MISO's control, MISO's attention would be better suited to understanding and addressing those issues than the ERAS process. NextEra further argues that a lack of requirements or criteria for prioritizing resources that use existing transmission capacity or minimize the need for new network upgrades will make ERAS more susceptible to ongoing supply chain delays or may increase the time and costs for constructing required network upgrades; may constrain MISO staff resources; and/or may increase the risk of ERAS interconnection customers dropping out due to high network upgrade costs or long network upgrade construction schedules.[135]

55. Several protesters argue that the Revised ERAS Proposal is not appropriately tailored to timely meet MISO's resource adequacy needs because the commercial operation deadline requirements are too far out into the future.[136] COMPP contends that

---

[131] Clean Energy Associations Docket No. ER25-1674 Protest at 46-47; Clean Grid Alliance Protest at 2; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 25.

[132] Clean Grid Alliance Protest at 2. *See also Midcontinent Indep. Sys. Operator, Inc.*, 176 FERC ¶ 61,161 (2021) (granting waiver of the Tariff to allow a one or two-year extension of the commercial operation deadline for certain interconnection requests in MISO's August 2017 DPP West study group).

[133] Clean Energy Associations Docket No. ER25-1674 Protest at 46-47; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 25; 2025 Brattle Group Report at 26.

[134] Clean Energy Associations Docket No. ER25-1674 Protest at 47.

[135] 2025 Brattle Group Report at 26.

[136] Clean Energy Associations Docket No. ER25-1674 Protest at 46; COMPP Protest at 4; Invenergy Protest at 9-10; Michigan Commission Protest 12-14; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 21-22

the Revised ERAS Proposal does not address the Commission's concerns in the May 2025 Order and allows for ERAS interconnection requests to achieve commercial operation as late as 2035, when MISO forecasts a resource adequacy shortfall occurring between 2027 and 2030.[137] Similarly, Invenergy avers that the Revised ERAS Proposal weakens shovel readiness because the commercial operation date requirements would allow interconnection requests to be achieve commercial operation by as late as 2033.[138] MISO IPPs similarly argue that, instead of a three-year grace period, ERAS interconnection requests should be subject to higher penalties for delay or withdrawal than the DPP queue because they are given priority treatment in the ERAS process.[139] Michigan Commission additionally asserts that the Revised ERAS Proposal does not provide a stronger link between the interconnection request and the resource adequacy need because the Revised ERAS Proposal retains the three-year grace period for the commercial operation deadline, which does not narrowly tailor ERAS to only shovel-ready projects capable of meeting near-term resource adequacy challenges.[140] Michigan Commission argues that a three-year grace period, in addition to a three-year commercial operation date requirement for ERAS interconnection requests, is too long given the need for the addition of generating capacity by 2030 and belies the notion of the projects being "shovel ready," in contradiction to ERAS' stated purpose. Michigan Commission states that it is unclear why MISO appears reluctant to either eliminate the grace period or reduce it to one year and allow the Commission waiver process to handle longer lead time requests.

56. PIOs argue that MISO's Revised ERAS Proposal contains conflicting language with respect to the three-year grace period of the commercial operation date.[141]

(citing MISO Transmittal, Docket No. ER25-1674-000 at 21); PIOs Docket No. ER25-1674 Protest at 40-41.

[137] COMPP Protest at 4 (citing May 2025 Order, 191 FERC ¶ 61,131 at P 202). According to COMPP, MISO changed GIP section 4.4.4 to extend commercial operation deadlines for backlogged interconnection requests due to transmission owner construction delays by an additional 2.5 years beyond the three-year grace period, and some of these same transmission owners are seeking to interconnect generating facilities through ERAS. *Id.* n.7. *See Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,150 (2025).

[138] Invenergy Protest at 9-10.

[139] MISO IPPs Docket No. ER25-1674 Protest at 28.

[140] Michigan Commission Protest at 12-14.

[141] PIOs Protest at 37-38.

According to PIOs, MISO's transmittal states that "[a]ll ERAS projects are eligible to use the grace period of up to three years as documented in GIA Article 2.3.1." However, PIOs assert that Article 2.3.1 of the proposed *pro forma* EGIA does not directly describe a grace period, but instead refers to GIP section 4.4.4, which sets out the potential for a three-year grace period. Meanwhile, PIOs assert, the revised Tariff states that "[a]fter entering [ERAS], no changes to the In-Service Date or Commercial Operation Date of the Generating Facility is permitted via section 4.4.4."[142]

(c) RERRA Verification Requirement

57. Clean Energy Associations and EPSA aver that the RERRA verification does little to link the proposed ERAS interconnection request to the identified resource adequacy or reliability need.[143] Clean Energy Associations assert that the RERRA verification amounts to speculation by a group of states and local agencies that do not coordinate on resource adequacy and do not have the authority to determine the resource adequacy or reliability needs for the MISO-controlled transmission system.[144] Clean Energy Associations assert that proposed GIP section 3.9.1.1.ii allows projects to qualify based on support from a state integrated resource plan or similar mechanism, which directly contradicts the RERRA verification requirement in GIP section 3.9.1.1.i that an interconnection request not already be accounted for in an existing plan or procedure.[145] Clean Energy Associations further argue that the new provision that allows interconnection requests to bypass the Local Resource Zone requirement if an identified need appears in a RERRA's integrated resource plan or comparable document is similarly contradictory.

58. PIOs argue that despite MISO's proposal to change the RERRA requirement from a notification to a verification, it does not require the RERRA to explain its decision and how it compared similarly situated projects to choose the one best positioned to meet near-term resource adequacy needs.[146] PIOs add that nothing in the ERAS process requires a RERRA to consider whether a resource currently in the DPP is better suited to

[142] *Id.* at 38 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.8).

[143] Clean Energy Associations Protest at 11; EPSA Comments at 3.

[144] Clean Energy Associations Protest at 11.

[145] *Id.* at 11-12.

[146] PIOs Protest at 23 (quoting May 2025 Order, 191 FERC ¶ 61,131, (See, Comm'r, consenting at P 6).

meet the identified need.[147] PIOs contend that the first option for the RERRA verification focuses only on the load and not on the generation.

59. EPSA asserts that the Revised ERAS Proposal does not require RERRAs or others to explain why a given interconnection request is best positioned to meet near-term resource adequacy needs.[148] EPSA avers that the RERRA verification process is not objective or transparent enough to ensure that the interconnection requests are essential to addressing resource adequacy and reliability gaps.[149]

60. Several protesters argue that the Revised ERAS Proposal lacks specific criteria for how a RERRA will determine that a resource adequacy need exists and whether ERAS is necessary to meet such need.[150] Further, Invenergy argues that the proposal risks excluding projects that are best suited to meet resource adequacy needs.[151] Invenergy contends that the Revised ERAS Proposal is not narrowly tailored to resource adequacy needs because it lacks objective scoring criteria that the RERRAs will apply, such as was included in PJM Interconnection L.L.C.'s (PJM) Reliability Resource Initiative (RRI).[152] Similarly, EPSA contends that a more clear and specific qualitative scoring mechanism and/or selection process, such as part of the Interconnection Process Enhancements (IPE) that the Commission recently accepted for California Independent System Operator Corporation (CAISO), should be included in the Revised ERAS Proposal to ensure that resources proffered by RERRAs and the states are in fact essential to meet reliability and resource adequacy needs.[153] Invenergy asserts that MISO has not explained how an interconnection request will be evaluated, how a RERRA will target the most essential interconnection requests to address resource adequacy and reliability challenges, or how a

---

[147] *Id.* at 24.

[148] EPSA Comments at 3.

[149] *Id.* at 3, 6-7.

[150] Clean Energy Associations Docket No. ER25-1674 Protest at 44-45 (citing January 2024 Order, 186 FERC ¶ 61,054 at P 174); Invenergy Protest at 10; 2025 Brattle Group Report at 28.

[151] Invenergy Protest at 14.

[152] *Id.* at 10 (citing *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025) (PJM RRI Order), (Phillips and Rosner, Comm'rs consenting at P 1)).

[153] EPSA Comments at 3, 7 (citing *Cal. Indep. Sys. Operator Corp.*, 188 FERC ¶ 61,225, at P 173 (2024) (CAISO IPE Order) (accepting amendments to the LGIP in CAISO's tariff)).

RERRA will compare interconnection requests to determine which are best positioned to meet near-term resource adequacy and reliability needs.[154]

61. Constellation argues that the new RERRA verification requirements exacerbate the problems that the Commission highlighted in the May 2025 Order.[155] Constellation asserts that the Revised ERAS Proposal's requirement that, in non-retail-choice states, RERRAs verify specific load additions that projects will support is illusory because the verification "may take any form that works for a specific state."[156] Constellation contends that any number of interconnection requests can meet an identified need, resulting in a RERRA connecting load growth to an interconnection request with little effort.[157] Constellation asserts that, without objective and transparent standards, a RERRA may reject or accept any given interconnection request for inclusion in ERAS because each RERRA will have the exclusive discretion to decide inclusion. Thus, Constellation avers that the Revised ERAS Proposal does not provide objective criteria for RERRA verification to ensure that interconnection requests are best suited to quickly and efficiently meet identified resource adequacy and reliability needs.

(d) Other ERAS Eligibility Criteria

62. Protesters raise several other arguments for why they believe the proposed ERAS eligibility requirements and framework are not tailored to achieve MISO's stated objectives of meeting near-term resource adequacy and reliability needs. PIOs and Invenergy contend that MISO's proposed requirements for site control and NRIS may help to prevent speculative interconnection requests but do not ensure that "shovel ready" interconnection requests enter the ERAS process, such as evidence that major equipment or project permits have been sought or secured.[158] PIOs further contend that because ERAS interconnection customers will be competing with DPP interconnection customers for parts, labor, and necessary services, ERAS interconnection requests are likely to add to the challenges interconnection customers are already facing in getting resources to achieve commercial operation.[159] Invenergy further asserts that the Revised ERAS

---

[154] Invenergy Protest at 10-11 (citing May 2025 Order, 191 FERC ¶ 61,131 (See, Comm'r, consenting at P 6)).

[155] Constellation Protest at 2-3.

[156] *Id.* at 3 (citing Transmittal at 30).

[157] *Id.* (citing Transmittal at 13-18).

[158] Invenergy Protest at 9; PIOs Protest at 26.

[159] PIOs Protest at 26.

Proposal is not narrowly tailored due to is lack of objective criteria for interconnection requests to demonstrate shovel readiness.[160] Vistra asserts that the shortened timeline for the initial quarterly study period will likely limit independent power producer interconnection requests to smaller, less capital-intensive projects in order to meet the timeline, thus reducing their ability to meet regional resource adequacy needs.[161] Additionally, Constellation asserts that the serial nature of the ERAS study process means that interconnection requests will be studied on a first-come, first-served basis, which, Constellation contends, will have no bearing on an interconnection request's resource adequacy benefits.[162] According to Constellation, the quarterly study period will exclude interconnection requests within the same study area or impacting the same constraint, which may also harm resource adequacy.

63. Clean Grid Alliance asserts that MISO has not demonstrated how its proposal to study 68 ERAS interconnection requests will solve the claimed generating capacity shortfall or match such interconnection requests to locations where there are claimed needs.[163] Clean Grid Alliance argues that this contrasts with MISO's DPP queue cap, which has a "tether" based on non-coincident peak projections. Clean Grid Alliance further asserts that the Revised ERAS Proposal is not narrowly tailored because, unlike PJM RRI, ERAS will be processed in a separate queue.[164] PIOs contend that MISO's Revised ERAS Proposal, for which the closest comparison is the PJM RRI construct, includes a larger cap than PJM RRI despite MISO having less need for expedited interconnection than PJM.[165] Invenergy argues that MISO's proposed ERAS cap is untethered to resource adequacy or reliability needs due to its lack of scoring criteria.[166] Invenergy further argues that MISO's proposed carve out for independent power producers is not tied to any resource adequacy need or criteria, and as such, MISO may accept all 10 of the allotted independent power producer submissions in the first few

---

[160] Invenergy Protest at 3, 8-9.

[161] Vistra Protest at 10.

[162] Constellation Protest at 3-4.

[163] Clean Grid Alliance Protest at 23-24.

[164] *Id.* at 26.

[165] PIOs Protest at 19 (citing FERC, *2024: State of the Markets Staff Report* (Mar. 20, 2025), at 28 (Figure 17)).

[166] Invenergy Protest at 13.

cycles regardless of whether later submitted interconnection requests could better meet an identified need.

iii. Answers

(a) MISO Answer

64. MISO reiterates that there is significant evidence supporting its stated resource adequacy and reliability needs.[167] MISO points to statements made by Commission Chairman Mark Christie, provided during the June 2025 Technical Conference on resource adequacy, that MISO has lost 95 GW of accredited capacity and that load driven by data centers is increasing.[168] At the conference, MISO stated that it is resource adequate today, but that it is also working to slow the decline of other resources in its footprint and that more work is needed to arrest this decline and maintain capacity.[169] MISO recognizes that there was a spectrum of perspectives on the imminency of resource adequacy needs expressed at the conference, but MISO asserts that the general consensus was that MISO's queue is backlogged, retirements are outpacing additions, and load growth is increasing in the near-term. MISO emphasizes that these challenges are being experienced by RTOs/ISOs across the United States.[170]

65. MISO acknowledges that NERC has downgraded the MISO region's risk category for capacity shortfalls to "elevated risk" in the corrected NERC 2024 Long-Term Reliability Assessment, but MISO asserts that this new risk category places the MISO region at the same risk level as the PJM and CAISO regions, both of which recently proposed similar expedited generator interconnection queue processes through the RRI and IPE initiatives, respectfully.[171] MISO states that the corrected NERC 2024

---

[167] MISO Answer at 5.

[168] *Id.* at 5-6 (citing June 2025 Technical Conference, Day 2, Panel 5 at 2:00-4:00).

[169] *Id.* at 5-6 (citing June 2025 Technical Conference, Day 2, Panel 5, at 4:00-5:30).

[170] *Id.* at 6 (citing PJM Pre-filed Statement of Manu Asthana, June 2025 Technical Conference, at 2-3 (filed May 20, 2025); Pre-filed Statement of Elliott Mainzer, CAISO, June 2025 Technical Conference, at 7-9 (filed May 28, 2025); Pre-filed Statement of Pallas Lee Van Schaick, ISO-NE External Market Monitor and NYISO Market Monitoring Unit, June 2025 Technical Conference, at 2-4 (filed May 28, 2025); Pre-filed Statement of Gordon van Welie and Stephen George, ISO-NE, June 2025 Technical Conference, at 2-4 (filed May 28, 2025)).

[171] *Id.* (citing NERC, *Statement on NERC's 2024 Long-Term Reliability Assessment* (June 17, 2025) (NERC Statement on 2024 Long-Term Reliability

Long-Term Reliability Assessment places the MISO region into the "high risk" category during the 2028-2031 timeframe, and MISO asserts that this supports its claim that it has imminent resource adequacy and reliability needs. In addition, MISO states that the NERC 2025 Summer Reliability Assessment, which was not impacted by NERC's correction, found that the MISO region has potential for insufficient operating reserves in above-normal conditions.[172]

66. MISO also disagrees with protesters' assertions that the 2024 and 2025 OMS-MISO Surveys do not support the Revised ERAS Proposal.[173] MISO states that there is a general trend of declining generation additions, increased generation retirements, and unexpected large spot load development in the near term; thus, the resource adequacy challenges are broadly recognized and do not depend on the specific findings of one study. MISO contends that it cannot predict where large load development will occur and that it is trying to address resource adequacy and reliability problems that will occur in the future to prevent foreseeable shortfalls.[174] MISO asserts that the Revised ERAS Proposal is necessary to ensure that generation is built in time to meet future resource adequacy needs, even if it is resource adequate today.

67. Further, MISO states that, while protesters argue that MISO's automation efforts will resolve DPP study delays, its automation efforts currently focus only on DPP Phase I, with implementation in the more in-depth DPP Phase II and Phase III studies to occur later.[175] MISO contends that it will take several years before MISO experiences the benefit of recent reforms such as SUGAR implementation, GIP improvements, and the

---

Assessment) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx).

[172] *Id.* at 7 (citing NERC Statement on 2024 Long-Term Reliability Assessment; NERC, *2025 Summer Reliability Assessment* 6 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf).

[173] *Id.* (citing Clean Energy Associations Protest at 25-26; PIOs Protest at 29-33).

[174] *Id.* at 7-8.

[175] *Id.* at Tab B, Prepared Direct Testimony of Andrew Witmeier, Docket No. ER25-1674-000, at 10 (filed Apr. 21, 2025) (Witmeier Docket No. ER25-1674 Rebuttal Testimony).

2024 MISO Queue Cap, and ERAS is a separate process to address near-term resource adequacy needs.[176]

68. MISO also asserts that COMPP confuses the commercial operation date with the in-service date in arguing that the commercial operation date requirement was not appropriately tailored for ERAS interconnection requests to timely meet resource adequacy needs.[177] MISO explains that the Commission recently accepted, in Docket No. ER25-1758, revisions to its GIP that allow transmission owners to extend the in-service date during GIA negotiations for known construction delays, and to set a 180-day trial operation period after the in-service date. MISO contends that the 180-day trial operation period after the in-service date prevents the termination of an otherwise viable project in the very limited circumstance that the transmission owner had moved the in-service date for a facility that it was building and that was needed to allow a generating facility to provide its full output to the transmission system.[178] MISO states that these provisions do not allow the interconnection customer to extend its own commercial operation date grace period when the transmission system is ready to receive full output and do not impact commercial operation date timing requirements in GIP section 4.4.4 or *pro forma* GIA Article 2.3.1. MISO states that the grace period in the Revised ERAS Proposal is unchanged from the Initial ERAS Proposal and does not undercut the rationale for ERAS. MISO further asserts that any interconnection request can face in-service date and other delays and that arguments asserting that an interconnection request is not urgent because it may face in-service date delays are spurious. MISO asserts that the Revised ERAS Proposal accelerates those parts of the timeline that MISO can control.

69. Additionally, MISO states that the Revised ERAS Proposal better tailors the RERRAs' roles in ERAS to address resource adequacy needs because the new RERRA verification targets the resource adequacy need that an interconnection request is addressing and ensures that the interconnection request will address a new load addition or resource adequacy deficiency in the RERRA's footprint.[179] MISO explains that since resource adequacy determinations must be made in collaboration with the states, MISO relies on the RERRA to review and verify that the proposed interconnection request will

---

[176] MISO Answer, Tab B, MISO Answer, Docket No. ER25-1674-000, at 41 (filed Apr. 21, 2025) (MISO Docket No. ER25-1674 Answer).

[177] MISO Answer at 8-9 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,150; *see* MISO, Tariff, attach. X (GIP) (171.0.0), § 4.4.4.1).

[178] *Id.* at 9-10.

[179] *Id.* at 21.

address the identified need.[180] MISO states that the new verification requirement narrows ERAS interconnection requests to those that can address a resource adequacy need that a RERRA has verified is a valid, new, incremental load that is not already planned for, and for which an executed agreement exists connecting that need to the specific project.[181]

(b) Additional Answers

70. Clean Grid Alliance asserts that MISO's answer did not address the resource adequacy challenges that protesters raised and, instead, relied on NERC's new assessment downgrading MISO's risk to one similar to other RTOs/ISOs.[182] Clean Grid Alliance contends that, contrary to MISO's implications, the Commission did not grant exceptions to open access based on NERC capacity ratings. Further, Clean Grid Alliance reiterates that MISO has abundant generation because MISO has 56 GW of interconnection requests with GIAs and a large number of interconnection requests in the DPP 2021 and 2023 cycles that, according to MISO, will have GIAs in 2025 and 2026.[183] Clean Grid Alliance also contends that ERAS is unjustified and unnecessary because the provisional GIA process allows new generation to interconnect quickly.[184] Clean Grid Alliance further argues that MISO admits that ERAS projects may not be approved in state regulatory processes and may have to withdraw, which is contrary to MISO's claims that ERAS projects will be "shovel ready."[185]

71. Clean Grid Alliance reiterates that supply chain issues are the true cause of the DPP queue backlogs, which is evidenced by MISO's recent request for a blanket waiver to extend commercial operation deadlines for interconnection requests in the DPP 2018

---

[180] *Id.* at 22.

[181] *Id.* at 22-23.

[182] Clean Grid Alliance First Answer at 2-3 (citing Clean Grid Alliance Protest at 8; MISO Answer at 6). *See also* Clean Grid Alliance First Answer, attach. A (Clean Grid Alliance Answer), Docket No. ER25-1674-000 at 10 (filed May 2, 2025) (Clean Grid Alliance Docket No. ER25-1674 Answer).

[183] Clean Grid Alliance First Answer at 3; Clean Grid Alliance Docket No. ER25-1674 Answer at 11, 15.

[184] Clean Grid Alliance First Answer at 3, 5-6; Clean Grid Alliance Docket No. ER25-1674 Answer at 12-13.

[185] Clean Grid Alliance Docket No. ER25-1674 Answer at 13-14 (citing MISO Docket No. ER25-1674 Answer).

and 2019 cycles, citing supply chain issues.[186] Clean Grid Alliance avers that NERC also recognizes that supply chain issues are causing construction delays, resulting in a 2.7 GW shortfall in MISO's service territory.[187] Clean Grid Alliance asserts that establishing a separate ERAS study process is not going to solve the supply chain problem and may result in ERAS interconnection requests developing behind DPP interconnection requests with GIAs and those expected to finalize GIAs in 2025 and 2026.

72. Clean Grid Alliance asserts that LSEs and MISO correctly recognize that spot load is speculative and that there are only potential load growth issues.[188] Clean Grid Alliance avers that some LSEs identify specific generation needs but do not address why DPP interconnection requests cannot meet that load. Clean Grid Alliance also points out that other LSEs do not identify any specific needs.[189]

73. Finally, Clean Grid Alliance asserts that MISO is close to achieving a one-year processing time for its future DPP cycles due to implementing queue processing improvements, including the SUGAR software.[190] Clean Grid Alliance contends that MISO will be able to serve state load needs with resources in its DPP queue and that ERAS is thus unnecessary.

74. MISO IPPs aver that MISO's answer illustrates that the Revised ERAS Proposal is not narrowly tailored because MISO has not proffered any evidence connecting its proposed ERAS cap or carve outs with the magnitude of the anticipated resource adequacy shortfall, nor how the Revised ERAS Proposal will meet the timing of MISO's anticipated shortfall given that ERAS interconnection requests may not come online until 2032.[191]

75. Clean Energy Associations note that, in the time since MISO filed the Revised ERAS Proposal, NERC has revised the 2024 Long-Term Reliability Assessment to redesignate the MISO region from the "high risk" category to the "elevated risk"

---

[186] Clean Grid Alliance First Answer at 4 (citing Clean Grid Alliance Protest at 2); Clean Grid Alliance Docket No. ER25-1674 Answer at 11.

[187] Clean Grid Alliance First Answer at 4-5 (citing the NERC 2024 Long-Term Reliability Assessment at 43).

[188] *Id.* at 5-6 (citing MISO Answer at 7; Clean Grid Alliance Protest at 33).

[189] *Id.* at 6-7.

[190] Clean Grid Alliance Docket No. ER25-1674 Answer at 15.

[191] MISO IPPs Answer at 15.

category.[192] Clean Energy Associations assert that MISO, despite acknowledging the downgrade in its answer, still relies on the NERC definition of "high risk" to support its claimed imminent resource adequacy and reliability concerns.[193] Therefore, Clean Energy Associations argue that MISO's rationale for ERAS is based on inaccurate and overstated resource adequacy projections.[194]

76. Clean Energy Associations note that the 2025 OMS-MISO Survey demonstrates that the MISO region can maintain resource adequacy through 2031 through DPP and market reforms, improved resource deployment timelines, and other initiatives.[195] Clean Energy Associations argue that MISO fails to provide any evidence to rebut this statement from the 2025 OMS-MISO Survey or similar statements made by its IMM.[196] Accordingly, Clean Energy Associations assert that MISO already has the processes needed to address future resource adequacy problems. Clean Energy Associations further assert that, absent clear evidence of a near-term shortfall, there is no basis to adopt a new, preferential interconnection process.[197]

77. PIOs assert that MISO has neither addressed that its need to demonstrate that near-term resource adequacy needs justify the Revised ERAS Proposal nor why existing processes in MISO's Tariff are insufficient to meet its resource adequacy needs.[198]

78. PIOs argue that MISO's answer dismisses evidence regarding its resource adequacy needs.[199] PIOs contend that despite MISO's recognition of NERC's downgrading of MISO's risk assessment, MISO does not propose any adjustment to its Revised ERAS Proposal. PIOs further contend that, in arguing that its resource needs are equivalent to those of PJM and CAISO, MISO ignores critical differences among the Revised ERAS Proposal, PJM's RRI, and CAISO's IPE. Specifically, PIOs explain that

---

[192] Clean Energy Associations Answer at 3 (citing NERC Statement on 2024 Long-Term Reliability Assessment).

[193] *Id.* (citing MISO Answer at 7).

[194] *Id.* at 5.

[195] *Id.* at 3-4 (citing 2025 OMS-MISO Survey at 2).

[196] *Id.* at 4 (citing Clean Energy Associations Protest at 27-28).

[197] *Id.* at 5.

[198] PIOs Answer at 2.

[199] *Id.* at 3-4.

PJM has more significant issues with new entry and retirement of generating facilities compared to MISO, yet the RRI process has a smaller cap and stricter timeline criteria than the Revised ERAS Proposal. Further, PIOs state that CAISO's process prioritizes interconnection requests in the queue through scoring criteria rather than allowing new interconnection requests to "cut in line."[200]

79. PIOs argue that MISO continues to ignore significant timeline mismatches between its identified needs and the ERAS process. PIOs further argue that MISO's references to various timelines obfuscates the reality that ERAS interconnection requests are not more suited to meet near-term resource adequacy needs than interconnection requests in the DPP, particularly given the adoption of the SUGAR software through which MISO expects to process DPP backlogs by the end of 2026.[201]

80. PIOs argue that MISO's answer mistakes PIOs' and COMPP's concerns about the in-service date and commercial operation date to be solely about Tariff details and implementation, when the concern is more broadly that the Revised ERAS Proposal does not require ERAS interconnection requests to reach commercial operation in the near term.[202] PIOs contend that MISO's explanation that the Revised ERAS Proposal is only intended to accelerate the parts of the generator interconnection process that MISO can control demonstrates that the Revised ERAS Proposal does not include mechanisms to ensure that resources come online to meet near-term needs.[203] PIOs further contend that this explanation contradicts MISO's other statements that ERAS guarantees that only "shovel ready" interconnection requests will enter ERAS since MISO can only control certain aspects of the interconnection process, which will not be sufficient to ensure genuine shovel-readiness. PIOs assert that MISO's explanations also conflict with PJM's RRI, which includes indicators of readiness like a construction schedule and attestations of commercial operation timelines.[204]

c. Commission Determination

81. We find that MISO's Revised ERAS Proposal represents a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's urgent, near-term resource adequacy needs. MISO has authority to evaluate and maintain

---

[200] *Id.* at 4.

[201] *Id.* at 4-5.

[202] *Id.* at 5.

[203] *Id.* at 6.

[204] *Id.* (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 155).

resource adequacy under its Tariff mechanisms,[205] as well as to manage the processing of its queue.[206] We find that the Revised ERAS Proposal will allow MISO to accelerate the study of interconnection requests that are "shovel ready" and that will address an identified resource adequacy or reliability need in the same Local Resource Zone where the generating facility is to be located, with limited exceptions, thereby enabling resources to meet projected near-term resource adequacy needs more quickly than could be accomplished under MISO's current DPP process.

(a) MISO's Identified Need

82. We disagree with protesters that MISO has not sufficiently supported its near-term resource adequacy needs. While some protesters contend that MISO overstates its near-term resource adequacy needs, MISO cites several reports from different sources – MISO's Reliability Imperative Report, the 2024 and 2025 OMS-MISO Surveys, and the NERC 2024 Long-Term Reliability Assessment – as evidence of its near-term resource adequacy needs.[207] For example, while Clean Energy Associations assert that the 2025 OMS-MISO Survey projects a surplus of 1.4-6.1 GW, the next bullet in the survey results states that "at least 3.1 GW of additional capacity beyond the committed capacity will be needed to meet the projected planning reserve margin forecast."[208] Several commenters, both LSEs and state representatives, and some protesters have highlighted their near-term load-serving obligations and upcoming load needs.[209] MISO also asserts that the data it relies on, as well as the overall trends for

---

[205] *See Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176, at P 59 (2018) ("MISO's resource adequacy construct ensures just and reasonable rates by creating a price signal that reflects the availability of capacity rather than by creating any particular price"); *see also* January 2024 Order, 186 FERC ¶ 61,054 at P 182 ("[A]ny future section 205 filing to propose a study cycle cap must demonstrate how the cap ensures that MISO can study new generation seeking to interconnect in a manner that appropriately accounts for its future resource adequacy needs.").

[206] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 54 (citing *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114, at PP 15, 32 (2009) (finding that an RTO is entitled to flexibility in proposing variations to Commission requirements under the independent entity variation standard and that the RTOs' temporal and geographic queue clustering proposal was a rational approach), *order on compliance*, 129 FERC ¶ 61,226 (2009), *order on compliance*, 133 FERC ¶ 61,139 (2010)).

[207] Transmittal at 5-6.

[208] 2025 OMS-MISO Survey at 2.

[209] *See, e.g.*, AECS Comments at 4; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana

RTOs/ISOs throughout the country, support its claims about near-term resource adequacy needs.[210] While forecasting future resource adequacy needs necessarily involves uncertainty, we find that it is reasonable for MISO to act in recognition of the aforementioned reports. Further, we note that while NERC recently revised its 2024 Long-Term Reliability Assessment, MISO's risk classification for the years 2028-2031, remains in the "high risk" category.[211] ERAS provides a mechanism to accelerate the interconnection of resources to help address resource adequacy needs in MISO's footprint during this period. And as MISO points out, although NERC has downgraded the MISO region's risk category for capacity shortfalls to "elevated risk" before 2028, this new risk category places the MISO region at the same risk level as the PJM and CAISO regions, for which the Commission has also approved expedited generator interconnection study processes to address pressing resource adequacy needs.[212] We therefore find that MISO has sufficiently demonstrated that it has near-term resource adequacy needs in its region.

83. As for protesters' arguments about how the DPP process may meet MISO's identified resource adequacy needs in lieu of ERAS, we note that the Commission has extended RTOs/ISOs considerable flexibility in addressing region-specific interconnection study processing challenges.[213] In light of our finding that MISO's proposal is just and reasonable, we need not consider whether the proposal is more or less reasonable than the alternative solutions identified by protesters. Notwithstanding this, we disagree with arguments that MISO's recent interconnection study process reforms and study automation efforts will render the ERAS proposal unnecessary. While MISO's automation efforts may improve the overall DPP process,[214] those processing improvements are just now being implemented for the first time for the DPP 2022 cycle, which will not be completed for another year or more, and therefore are unlikely to be sufficient to meet MISO's near-term resource adequacy needs. At this time, only the system impact studies in the DPP process are being automated, while the ERAS

---

and Mississippi Commissions Comments at 5; Michigan Commission Protest at 7; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3; Mississippi Governor Comments at 1; Vistra Protest at 5, 7.

[210] MISO Answer at 5-8.

[211] Transmittal at 6 (citing the NERC 2024 Long-Term Reliability Assessment).

[212] *See* MISO Answer at 6.

[213] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 54.

[214] Witmeier Testimony at 64-65.

framework is designed to render EGIAs within 90 days,[215] with the entire ERAS process likely concluding well in advance of full implementation of DPP automation enhancement reforms.[216] Similarly, we agree with MISO that its interconnection study process reforms (e.g., the 2024 MISO Queue Cap) are focused on longer-term improvements to reduce speculative interconnection requests from entering the DPP queue and improve queue processing, not the objective of addressing near-term resource adequacy and reliability needs.

(b) Commercial Operation Date

84. Further, we disagree with protesters that MISO's proposed commercial operation date requirements undercut MISO's contention that ERAS interconnection requests will help resolve near-term resource adequacy needs. Under the Revised ERAS Proposal, interconnection customers must have a commercial operation date within three years of interconnection request submission, subject to an additional three-year grace period. Protesters argue that, as a result, ERAS generating facilities that will not come online for at least six years after interconnection request submission, and, for those submitted in 2027, as much as eight years from MISO's proposal, cannot address near-term resource adequacy or reliability needs. However, six years is the worst-case scenario, reflecting the maximum period for an ERAS generating facility to come online, which nevertheless is nearly half of the maximum 11-year commercial operation deadline that is used by some DPP interconnection requests.[217] Further, while there is no guarantee that all ERAS interconnection requests will achieve commercial operation, it is reasonable to conclude that ERAS interconnection requests are more likely to do so than DPP interconnection requests given the ERAS eligibility requirements designed to swiftly identify "shovel ready" projects. We agree with commenters that MISO's proposed coupling of its proposed commercial operation date requirements and stringent eligibility requirements will enable MISO to accelerate the study of urgently needed, "shovel ready" projects to help alleviate near-term resource adequacy needs.[218]

85. With respect to protester arguments that the proposed language in GIP section 3.9.8 may conflict with MISO's assertion that "[a]ll ERAS projects are eligible to

---

[215] Transmittal at 8.

[216] *See* MISO Answer at 6-7.

[217] Witmeier Testimony at 47.

[218] Transmittal at 39; MISO Answer at 29; AECS Comments at 4; Big Rivers Electric Comments at 3; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3.

use the grace period of up to three years as documented in GIA Article 2.3.1,"[219] we note that GIP section 3.9.8 addresses modifications to the ERAS interconnection request, and not to the EGIA.

(c) RERRA Verification Requirement

86. Contrary to Clean Energy Associations' assertions,[220] we do not believe that MISO's proposed GIP section 3.9.1 is contradictory. Rather, we find that proposed GIP section 3.9.1.1.i provides requirements for the RERRA's written verification with respect to "new, incremental load" whereas proposed GIP section 3.9.1.1.ii provides requirements for the RERRA's written verification with respect to "a resource adequacy deficiency" with multiple means by which such a determination can be supported.

87. For example, under proposed GIP section 3.9.1.1.ii, MISO provides examples of supporting materials that "can" support a determination that the proposed interconnection request will address an identified resource adequacy need, including integrated resource plans.

88. In response to PIOs' concerns that nothing in the ERAS process requires a RERRA to consider whether a resource currently in the DPP is better suited to meet the identified need, we note that the DPP is a MISO-specific process outside of a RERRA's purview. Further, nothing prohibits an interconnection customer with an interconnection request in the DPP from participating in the ERAS process if it satisfies the ERAS eligibility requirements.

(d) Other ERAS Eligibility Requirements

89. As further discussed below, we find that MISO has sufficiently detailed the parameters of ERAS eligibility in the proposed Tariff, and MISO has narrowly tailored the Revised ERAS Proposal to the identified near-term resource adequacy or reliability needs.[221] Moreover, as for protester suggestions that the RERRA verification should incorporate a scoring mechanism or other alternative approaches, we reiterate our earlier finding that the Commission affords MISO considerable flexibility in addressing region-specific interconnection queue processing challenges, and we need not consider whether

[219] Transmittal at 50.

[220] Clean Energy Associations Protest at 11-12.

[221] *See* discussion *infra*, parts IV.B.2.c, 3.c., 4.c and 5.c.

MISO's proposal is more or less reasonable than the alternative solutions identified by protesters.[222]

2. Jurisdiction and Filed Rate Doctrine

a. MISO's Filing

90. MISO states that the FPA and Commission precedent recognize the authority of state regulators and their jurisdictional utilities to plan for adequate generation to address resource adequacy needs within their jurisdictional footprints.[223] MISO further states that the Revised ERAS Proposal incorporates the role of states and other RERRAs and "provides a vehicle for the RERRA to verify to MISO that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed Generating Facility will address an identified resource adequacy deficiency."[224] MISO's statement is a reference to the RERRA verification eligibility requirement in proposed GIP section 3.9.1, which provides that:

> 1. The Interconnection Request shall be accompanied by a written verification from the RERRA (or its documented representative) where the load to be served by the Generating Facility is located and, subject to the procedures the RERRA requires, that either:
>
> a. The new, incremental load addition claimed by the interconnection customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview; or
>
> b. The generating facility proposed by the interconnection customer will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer as supported by certain documentation; or
>
> c. For generating facilities that will address a resource adequacy deficiency and either serves retail load or a retail choice state, the interconnection customer will

[222] *See supra* P 82.

[223] Transmittal at 2.

[224] *Id.* at 9.

> indicate the specific load as required in the interconnection request and provide evidence that the generating facility will address a resource adequacy deficiency as described in (b), but such interconnection customer will not be required to include a written verification from the RERRA.

b. Responsive Pleadings

i. Comments in Support

91. Some commenters assert that ERAS aligns with state jurisdictional authority as it relates to decision-making on resource adequacy.[225] AECS notes that the process respects state authority over resource procurement and ensures that RERRAs will determine the resources necessary to support LSEs under their jurisdiction.[226] Louisiana and Mississippi Commissions assert that the verification process accommodates the needs of the various MISO states, both regulated and those with retail access.[227] MISO TOs state that, according to Commission precedent, states have authority over resource adequacy, and ERAS intentionally empowers states and RERRAs with the ability to signal to MISO, through the RERRA verification process, that certain projects need the expedited treatment of the ERAS process. Additionally, MISO TOs note that MISO added Tariff language incorporating the retail access states into the ERAS process to address resource adequacy deficiencies in those states, recognizing the structural differences in those states.[228] Texas Commission asserts that there is a need to study interconnection requests that are necessary to meet nearer-term, state-determined resource adequacy needs because there is an increasing risk of a state's "needs determination" being unmet if an interconnection request is delayed in MISO's queue.[229]

---

[225] AECS Comments at 6; Entergy/Cleco/Cooperative Energy Comments at 3, 8; Louisiana and Mississippi Commissions Comments at 3, 9; MISO TOs Comments at 3, 10-11; Missouri Commission Comments at 2; Texas Commission Comments at 5-7.

[226] AECS Comments at 6.

[227] Louisiana and Mississippi Commissions Comments at 9.

[228] MISO TOs Comments at 10-11.

[229] Texas Commission Comments at 7.

ii. Protests

92. NextEra and MISO IPPs assert that the ERAS proposal unjustly and unreasonably allows states to set the terms and conditions of Commission-jurisdictional service, despite the FPA granting, and the courts upholding, exclusive jurisdiction over the rates, terms, and conditions for the transmission of electric energy in interstate commerce, including interconnection service, to the Commission.[230] Further, NextEra and MISO IPPs state that ERAS essentially grants RERRAs the authority to determine which interconnection customers will be granted interconnection service, which is a Commission-exclusive jurisdiction.[231] Additionally, NextEra asserts that MISO is required to provide nondiscriminatory open access to the transmission system in a manner that allows all resources to compete on equal footing, which will not infringe on states' authority over resource adequacy, so long as MISO does not mandate or prohibit any particular generating facility or resource mix.[232] In support of this, NextEra and MISO IPPs argue that the Commission rejected past proposals as unduly discriminatory when they prioritized resources that were being developed in connection with a state resource

[230] *See* NextEra Docket No. ER25-1674 Protest at 6, 48-49 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 288 (2016); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 164 (2016) (*Talen*); and PJM RRI Order, 190 FERC ¶ 61,084 at P 75); MISO IPPs Docket No. ER25-1674 Protest, Affidavit of the Hon. Joseph T. Kelliher ¶ P 16 (Kelliher Aff.).

[231] MISO IPPs Docket No. ER25-1674 Protest at 13-14 (citing *FPL Energy Marcus Hook, L.P. v. FERC*, 430 F.3d 441, 443 (D.C. Cir. 2005); PJM RRI Order, 190 FERC ¶ 61,084 at P 75); NextEra Protest at 49.

[232] NextEra Docket No. ER25-1674 Protest at 50 (citing *Xcel Energy Operating Cos.*, 106 FERC ¶ 61,260, at P 23 (2004) (*Xcel*) (rejecting a proposal to provide priority queue access to interconnection requests that were part of a state-sponsored bidding process and finding that interconnection customers that did not take part in the state-sponsored bidding must be allowed to compete in the wholesale energy market on an equal footing); PJM RRI Order, 190 FERC ¶ 61,084 at P 76).

solicitation process[233] and rejected the RERRA exclusion in the 2023 MISO Queue Cap Proposal.[234]

93. NextEra asserts that, due to the non-delegation doctrine, neither MISO nor the Commission can delegate authority over the rates, terms, and conditions of interconnection service to RERRAs.[235] NextEra argues that there is a presumption against subdelegation, even if that subdelegation is to a state commission, which may be a RERRA under the ERAS process.[236] NextEra asserts that RERRAs are not subject to Commission oversight, so it is not clear that the Commission can exercise oversight of RERRA rates via FPA section 206[237] complaint proceedings, which would violate the non-delegation doctrine and the FPA.[238] Clean Energy Associations argue that "MISO is effectively delegating to states its responsibility for ensuring that its own Tariff is not unduly discriminatory or preferential, and thereby leaving the Commission without oversight."[239] Additionally, Clean Energy Associations state that MISO has failed to

---

[233] MISO IPPs Docket No. ER25-1674 Protest at 7-8 (citing *Sw. Power Pool, Inc.*, 147 FERC ¶ 61,201, at P 124 (2014)); NextEra Docket No. ER25-1674 Protest at 8 (citing *Xcel*, 106 FERC ¶ 61,260 at PP 12-13, 22-24); *Midwest Indep. Transmission Sys. Operator, Inc*., 124 FERC ¶ 61,183, at P 143 (2008)).

[234] NextEra Docket No. ER25-1674 Protest at 9 (citing January 2024 Order, 186 FERC ¶ 61,054 at PP 176-177).

[235] *Id.* at 53.

[236] *Id.* (citing *U.S. Telecom Ass'n v. FCC*, 359 F.3d 554, 566 (D.C. Cir. 2004) (*U.S. Telecom*); *Texas v. Rettig*, 987 F.3d 518, 531 (5th Cir. 2021)); *see also* MISO IPPs Docket No. ER25-1674 Protest at 15 (citing Kelliher Aff. at 6-7).

[237] 16 U.S.C. § 824e.

[238] NextEra Docket No. ER25-1674 Protest at 53-54 (citing *La. Pub. Serv. Comm'n v. FERC*, 761 F.3d 540, 552 (5th Cir. 2014) (*Louisiana PSC*); *see Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1.

[239] Clean Energy Associations Docket No. ER25-1674 Protest at 22.

meet its obligations as an independent system operator under Order No. 888 to ensure fair and non-discriminatory access to transmission services and ancillary service for all users of the transmission system.

94. Finally, NextEra and MISO IPPs assert that ERAS violates the filed rate doctrine because a RERRA will establish the criteria used to determine ERAS participation without filing with the Commission and without providing uniform, objective, and non-discriminatory criteria in the tariff, which will circumvent the Commission's jurisdictional authority to ensure that the terms and conditions of receiving interconnection service in MISO are just and reasonable and not unduly discriminatory or preferential.[240] NextEra additionally argues that the fact that RERRAs can set their own criteria for resources to enter ERAS also will result in similarly situated interconnection customers within the MISO region being subject to arbitrary differences in the terms and conditions of interconnection service, depending on its applicable RERRA.[241] NextEra further argues that interconnection customers will not receive notice of the terms and conditions of the RERRA's criteria, as the FPA requires.[242] MISO IPPs assert that a lack of objective criteria in the Tariff will create an environment ripe for undue discrimination in the RERRA approval process, and thus the composition of the ERAS queue.[243]

95. Clean Grid Alliance argues that MISO's discussion of jurisdiction is intended to divert attention from the deficiencies in the Revised ERAS Proposal and that, while RERRAs should have a role over resource adequacy, MISO must still comply with open access requirements.[244] Similarly, COMPP asserts that though resource adequacy decisions rest within state jurisdiction, MISO's role is to meet the Commission's reliability standards while adhering to open access principles, and such principles are not being met by the Revised ERAS Proposal.[245] PIOs argue that MISO's refusal to exert

[240] MISO IPPs Docket No. ER25-1674 Protest at 14; NextEra Docket No. ER25-1674 Protest at 52.

[241] NextEra Docket No. ER25-1674 Protest at 17-18.

[242] *Id.* at 52-53.

[243] MISO IPPs Docket No. ER25-1674 Protest at 15 (citing Kelliher Aff. at 6-7).

[244] Clean Grid Alliance Protest at 30.

[245] COMPP Protest at 7-8.

any oversight over the RERRA authority continues to go "beyond appropriate respect" for states' role in resource adequacy.[246]

iii. Answers

(a) MISO Answer

96. MISO asserts that the Revised ERAS Proposal reflects and respects the unique jurisdictional divide between the states, MISO, and the federal government. MISO reiterates that it is the states, not MISO, that have the power to determine the resources that will be used in states' jurisdictions.[247] MISO asserts that because there are a wide variety of RERRAs, it was required to design a flexible enough process to accommodate this variety. MISO argues that the additional eligibility requirements ensure that there are uniform, objective criteria in the Tariff.[248] MISO contends that states are not setting the rates, terms, and conditions of interconnection service; rather, RERRAs determine need within their jurisdictional processes, and that regardless of that determination, ERAS interconnection requests will still need to go through the approval process outside of ERAS.[249]

c. Commission Determination

97. We disagree with protesters that the Revised ERAS Proposal intrudes upon the Commission's exclusive FPA jurisdiction over generator interconnection. We disagree that the precedent cited by protesters indicates that the role of states, as RERRAs, in the ERAS process is impermissible.

98. Specifically, NextEra points to *Talen* to argue that even if states have authority over generating facilities, that does not permit them to "exercise control over the terms and conditions of interconnection service."[250] In *Talen*, incumbent generators brought suit to challenge a Maryland Public Service Commission (Maryland Commission) order that required LSEs in Maryland to buy capacity from a specific generator and pay the difference between the Commission-jurisdictional PJM interstate wholesale capacity auction clearing price and a price that the Maryland Commission guaranteed. The

---

[246] PIOs Protest at 24 (quoting May 2025 Order, 191 FERC ¶ 61,13 (See, Comm'r, consenting at P 6)).

[247] MISO Answer at 4, 22, 25-26, 30.

[248] MISO Docket No. ER25-1674 Answer at 15.

[249] *Id.* at 16.

[250] NextEra Docket No. ER25-1674 Protest at 50 (citing *Talen*, 578 U.S. at 164).

Supreme Court of the United States (Supreme Court) rejected the Maryland program, stating that "[b]y adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf."[251] The Supreme Court stated that "[s]tates may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority"[252] and that states "interfere with FERC's authority by disregarding interstate wholesale rates FERC has deemed just and reasonable, even when [s]tates exercise their traditional authority over . . . in-state generation."[253] The Supreme Court went on to say, however, that "[n]othing in this opinion should be read to foreclose . . . [s]tates from encouraging production of new or clean generation through measures 'untethered to a generator's wholesale market participation.'"[254]

99. We find that the Revised ERAS Proposal is permissible under *Talen* because RERRA participation in the ERAS process would be wholly pursuant to a Commission-jurisdictional process (i.e., the generator interconnection process), proposed by MISO and approved by the Commission—not by state authorities—and under which a GIP is on file with the Commission and any future revisions would be subject to Commission approval. Further, the ERAS process would remain subject to the Commission's authority pursuant to FPA sections 205 and 206. In contrast, in *Talen*, the Maryland Commission established a state program that operated outside a Commission-jurisdictional process and "interfered" with the Commission's authority to establish interstate wholesale rates. Nothing in the Revised ERAS Proposal deprives the Commission of its statutory jurisdiction as it applies to generator interconnection.

100. Similarly, we disagree with MISO IPPs' claim that, based on *U.S. Telecom*, the Revised ERAS Proposal impermissibly requires the Commission to subdelegate its FPA authority to the RERRAs. In that decision, which involved the Federal Communications Commission's (FCC) subdelegation to state commissions certain determinations that the FCC was required to make pursuant to the Telecommunications Act of 1996,[255] the United States Court of Appeals for the District of Columbia Circuit determined that the

[251] *Talen*, 578 U.S. at 163.

[252] *Id.* at 164.

[253] *Id*. at 165.

[254] *Id.* at 166.

[255] 47 U.S.C. § 151 *et seq.*

FCC's subdelegation had, in some respects, given the state commissions "unlimited discretion."[256]

101. We find that *U.S. Telecom* is distinguishable from the Revised ERAS Proposal. The Revised ERAS Proposal does not subdelegate the Commission's authority but simply creates a role for RERRAs in a Commission-jurisdictional process.[257] In particular, the RERRA's role would be limited to assessing and verifying non-speculative interconnection requests that address an identified resource adequacy deficiency. In this way, the Revised ERAS Proposal also recognizes the states' jurisdictional authority over resource planning and the generation mix within their boundaries. Further, in *Louisiana PSC*, the United States Court of Appeals for the Fifth Circuit determined that it is not an unlawful subdelegation for the Commission to incorporate state-determined rate elements in Commission-jurisdictional rate proceedings.[258] According to the court, the Commission's "continuing review in Section 206 proceedings distinguishes it from the unease expressed in [*U.S.*] *Telecom,* of agencies' 'vague or inadequate assertions of final reviewing authority.'"[259] Similarly, under the Revised ERAS Proposal, the RERRA is given a limited role in verifying interconnection requests, and such requests, through the EGIA process, would be subject to Commission review under FPA sections 205 and 206.

102. We also disagree with NextEra and MISO IPPs that the Revised ERAS Proposal violates the filed rate doctrine. The filed rate doctrine and the rule against retroactive ratemaking are "the statutory requirements that bind regulated entities to charge only the rates filed with [the Commission] and to change their rates only prospectively."[260] The FPA requires public utilities to file with the Commission the rates, terms, and conditions

---

[256] *U.S. Telecom*, 359 F.3d at 564.

[257] *See, e.g.*, *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247, at P 64 (2020) (finding that small utilities may not participate in distributed energy resource aggregations unless the RERRA affirmatively allows such customers to participate in distributed energy resource aggregations), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[258] *Louisiana PSC*, 761 F.3d at 551-52 (holding that there was no unlawful subdelegation where the Commission exercised its role by reviewing and accepting a bandwidth formula that incorporated state agencies' depreciation rates).

[259] *Id*. at 552 (quoting *U.S. Telecom*, 359 F.3d at 568).

[260] *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021); *see also PJM Power Providers Grp. v. FERC*, 96 F.4th 390, 394 (3rd Cir. 2024).

of the jurisdictional service they provide.[261] NextEra and MISO IPPs argue that the Revised ERAS Proposal violates the filed rate doctrine because it allows RERRAs to establish criteria that would not be on file with the Commission and that would determine whether or not an interconnection request is eligible for ERAS.[262] We disagree. We find that the Revised ERAS Proposal does not present a filed rate doctrine concern because it provides adequate notice of the ERAS eligibility requirements, including the RERRA verification requirement.[263] In particular, the RERRA verification requirement in proposed GIP section 3.9.1.1 has multiple sub-requirements that provide a level of uniformity among RERRAs, such as the requirement that the RERRA must be from the same location as the load to be served, and the requirement that the RERRA verification must include an explanation of how the generating facility associated with the interconnection request will address a resource adequacy need, among other things.[264] If the RERRA verification does not satisfy these requirements, then the interconnection request would not be eligible for ERAS. Thus, we find that MISO has sufficiently detailed the parameters of ERAS eligibility, including the RERRA verification requirement, to satisfy the filed rate doctrine.

3. ERAS Requirements and Open Access/Undue Discrimination Concerns

a. MISO's Filing

i. RERRA Verification

103. As noted above, MISO proposes to require that to qualify for ERAS, an interconnection request must include a written verification from the RERRA, or RERRA representative where the load to be served by the generating facility is located, that requires either:

---

[261] 16 U.S.C. § 824d(c); *see* 18 C.F.R. § 35.1(a) (2024) (requiring that any "rates and charges . . . classifications, practices, rules and regulations affecting such rates, charges, classifications, services, rules, regulations or practices," be filed with the Commission).

[262] *See* MISO IPPs Docket No. ER25-1674 Protest at 14; NextEra Docket No. ER25-1674 Protest at 51-53.

[263] *See, e.g.*, *Consol. Edison Co. of N.Y. v. FERC*, 347 F.3d 964, 969 (D.C. Cir. 2003); *Columbia Gas Transmission Corp. v. FERC*, 895 F.2d 791, 795-97 (D.C. Cir. 1990).

[264] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.

a. The new, incremental load addition claimed by the interconnection customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview; or

b. The generating facility proposed by the interconnection customer will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer, which can be supported by: (i) a state energy forecast, or other forward-looking forecast; (ii) commencement of a state proceeding; (iii) review of a RERRA, LSE, or other state resource plan or document, which may include, but is not limited to: integrated resource plans, procurement plans, or other plan or study types; (iv) response to a request for proposals; or (v) other process, or delegation of authority, as determined by the RERRA or RERRA regulations (including in retail choice states).

For generating facilities that will address a resource adequacy deficiency and either serve retail load or a retail choice state, the interconnection customer will not be required to include a written verification from the RERRA. Instead, the interconnection customer will indicate the specific load as required in the interconnection request and provide evidence that the generating facility will address a resource adequacy deficiency as described in (b).

104. MISO states that it changed this requirement, from the RERRA notification in the Initial ERAS Proposal,[265] to better target the resource adequacy driver that an ERAS interconnection request addresses and to ensure that the RERRA verifies that such interconnection request will address a new load addition or a resource adequacy deficiency in its footprint.[266] MISO further states that the revised requirement is critical to maintaining the limited scope of ERAS to address near-term resource adequacy and/or reliability need claimed by an interconnection customer in a RERRA. MISO explains

[265] In the Initial ERAS Proposal, MISO proposed to require that an ERAS interconnection request be accompanied by a written notification from the RERRA specifying where the load to be served is located and that the interconnection request should be included in ERAS.

[266] Transmittal at 30.

that the RERRA verification may take any form so long as it is made by the RERRA or RERRA representative.

105. MISO states that the third option related to the RERRA verification was added to incorporate retail choice states – Illinois and a portion of Michigan.[267] Under this option, rather than requiring RERRA verification, MISO proposes to notify the respective RERRA that an ERAS interconnection request was submitted and provide a copy of the interconnection request. MISO states that the RERRA will have 10 business days from the date of notification to state that the interconnection request should not be included in ERAS. MISO states that this aspect of its proposal recognizes that interconnection customers in retail choice states do not need to seek approval from a RERRA and that there are alternative retail electric suppliers that serve load. MISO asserts that this language better facilitates the use of ERAS in Illinois and the retail choice areas of Michigan without changing the role or requirements for RERRAs in other parts of MISO's footprint.

106. MISO asserts that it is not a resource planner, so it is reasonable to require a RERRA verification for consideration in the ERAS process.[268] MISO explains that, in fact, the FPA recognizes that the RERRAs have jurisdiction over resource adequacy needs.[269] Therefore, MISO states that including the RERRA verification requirement ensures that an ERAS interconnection request is tied to a specific resource adequacy or reliability need.[270] MISO adds that this requirement will prohibit the submission of speculative interconnection requests with no connection to a specific need.[271] MISO states, however, that the RERRA verification requirement is not intended to constitute a final determination on the need or suitability of the interconnection request. Rather, MISO emphasizes that the RERRA verification is only a condition for requesting that MISO study a proposed interconnection request in the ERAS process.[272]

---

[267] *Id.* at 31.

[268] Witmeier Testimony at 31.

[269] Transmittal at 2 (citing 16 U.S.C. § 824; *CXA La Paloma, LLC v. Cal. Indep. Sys. Operator Corp.*, 165 FERC ¶ 61,148, at P 70 (2018)).

[270] *Id.* at 30.

[271] Witmeier Testimony at 32. MISO states that verification is only needed from one RERRA for an application for ERAS participation. *Id.* at 35.

[272] Transmittal at 31, 52.

107. MISO states that due to its unique composition of almost entirely vertically integrated utilities, resource adequacy decisions must be made in collaboration with the states.[273] MISO explains that responsibility for addressing resource adequacy or reliability needs is a state responsibility and that it would be inappropriate for MISO to make selections to address these needs. MISO states that the Revised ERAS Proposal accounts for its unique composition and the division of jurisdictional authority by proposing that MISO only facilitate the ERAS process and that interconnection customers identify the specific needs their interconnection requests address, and that RERRAs (including states) verify to MISO which interconnection requests merit expedited study.

ii. Executed Agreement Requirement

108. MISO also proposes to require an ERAS interconnection customer to have an executed agreement evidencing that its interconnection request "is intended to be used by the entity with the claimed resource adequacy or reliability need" (executed agreement requirement).[274] MISO proposes that the required agreement can take the form of: (1) an LSE acknowledgement to self-supply; (2) a power purchase agreement (PPA) or a similar off-take agreement between the ERAS interconnection customer and the entity to be served (including, but not limited to, an alternative retail electric supplier or its LSE); (3) an agreement that provides for the transfer of ownership or control of the generating facility to the entity with the load to be served (including, but not limited to, an alternative retail electric supplier or its LSE) after such generating facility is developed by the interconnection customer; or (4) an "other" agreement between the ERAS interconnection customer and the entity with the load to be served (including, but not limited to, an alternative retail electric supplier or its LSE), stating that the ERAS interconnection request will be used to meet an identified resource adequacy deficiency.[275]

109. MISO states that this requirement will ensure that an ERAS interconnection request is intended to be used by the entity with the claimed resource adequacy or reliability need.[276] MISO explains that such a requirement prevents speculative interconnection requests with no commercial arrangements from participating in ERAS.

---

[273] *Id.* at 19.

[274] *Id.* at 30; Witmeier Testimony at 39, 41; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.2.

[275] Transmittal at 30-31; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.2.

[276] Transmittal at 30.

MISO states that, for example, an interconnection customer that has an agreement with a data center developer for the generation to serve that load is differently situated from an interconnection customer that enters the queue with the hope of pitching their generation project to the developer. MISO adds that, based on stakeholder feedback, it expanded the ERAS process to allow independent power producers to participate through inclusion of an "other" type of executed agreement.[277] MISO asserts that the executed agreement requirement mitigates overuse concerns because it pairs an ERAS interconnection request with a specific need.[278]

iii. ERAS Cap and Carve Outs

110. MISO proposes to establish a limit on the total number of interconnection requests that can participate in the ERAS process to 68. Of the 68 total interconnection requests, MISO proposes to allow a maximum of 10 interconnection requests from independent power producers that have agreements with entities other than LSEs and a maximum of 8 interconnection requests to serve retail choice load.[279] MISO states that the remaining 50 interconnection requests allowed to participate in ERAS will be for the remaining applicants for non-retail choice states. In addition, MISO proposes to implement a limit on the total number of interconnection requests that may be studied in an ERAS quarterly study period to 10 interconnection requests. MISO states that the interconnection requests will be selected based on the time stamp of submission, and it will create a waitlist for interconnection requests beyond the tenth submission. MISO further states that it will screen the submitted interconnection requests to ensure that none are in the same geographical area or impacting the same constraint. MISO states that, if any of the interconnection requests are in the same geographical area or impact the same constraint, then the one with a later time submission will be deferred to the next available ERAS quarterly study period. MISO explains that in the event that an interconnection request is deferred to a future ERAS quarterly study period, it will review any ERAS interconnection requests on the waitlist to determine whether one can be moved up into the deferred interconnection request's spot. Accordingly, MISO states that it will confirm that an interconnection request from the waitlist is not in the same geographic area as those in the ERAS quarterly study period under review. MISO states that these proposed limitations are in response to the Commission's feedback in the May 2025 Order.

111. MISO states that these proposed limitations will enable MISO to complete the ERAS process more efficiently and will result in interconnection customers receiving an

[277] *Id.* at 41.

[278] *Id.* at 31.

[279] *Id.* at 25-26; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.2.

EGIA quickly. MISO further states that the proposed limitations will allow MISO to better plan for the number of interconnection requests requiring study each quarterly study period and to better coordinate internal resources.[280] MISO states that while it stands by its original assertions that the ERAS process will not affect DPP interconnection requests and that the strict eligibility requirements will limit interconnection request submissions, expressly capping the number of interconnection requests will further ensure that DPP interconnection customers are not harmed by the ERAS process.[281] MISO asserts that its proposed cap serves the same goal as PJM's RRI, to "reasonably balance the need to address … resource adequacy challenges with the need to avoid an influx of projects that could overwhelm … [MISO's] interconnection process," but that MISO's proposal is spread over a longer period of time than PJM's RRI in order to allow prospective interconnection customers time to fully prepare their interconnection requests.[282]

iv. Other ERAS Eligibility Requirements

112. MISO proposes several requirements for ERAS interconnection requests, in addition to the demonstrations discussed above. Specifically, MISO proposes that interconnection customers must provide a non-refundable $100,000 D1 application fee and a refundable M2 amount of $24,000/MW and meet a requirement for 100% site control for both the generating facility and interconnection customer's interconnection facilities.[283]

113. MISO states that the non-refundable $100,000 D1 application fee, which is higher than the $5,000 D1 amount (even as adjusted for inflation) in the DPP, is necessary to prevent speculative interconnection requests from applying to the ERAS process, implement the temporary ERAS process, and cover costs associated with processing ERAS interconnection requests.[284] MISO states that the M2 amount of $24,000/MW (relative to $8,000/MW in the DPP) is based on MISO's existing provisional interconnection service milestone requirements and represents the same level of upfront financial commitment for this "one phase" process that an interconnection customer otherwise would make cumulatively for the "three phase" M2, M3, and M4 milestones in

[280] Transmittal at 26.

[281] *Id.* at 27.

[282] *Id.*

[283] *Id.* at 36.

[284] *Id.* at 49.

the DPP process.[285] MISO adds that in addition to the RERRA verification and executed agreement requirements, the milestone payments and deposits are required at the time of application to allow MISO to complete the ERAS process within the estimated 90-day timeframe.[286]

114. MISO states that it is reasonable to require 100% site control for both the generating facility and interconnection customer's interconnection facilities for ERAS interconnection requests because it ensures that MISO will not be inundated with speculative interconnection requests. MISO explains that this requirement is more stringent than the requirements for the DPP, which only requires a 100% site control demonstration for the generating facility and a 50% demonstration of site control for interconnection customer's interconnection facilities at the time of an application submission. MISO also asserts that its proposal to disallow financial security in lieu of the proposed site control requirements will deter speculative interconnection requests because it prohibits such requests from being eligible for the ERAS process if they are unable to obtain necessary permits or siting requirements.[287]

115. MISO proposes to require that an ERAS interconnection request identify the claimed resource adequacy and/or reliability need for which the interconnection request is being submitted.[288] MISO states that this must include the location of the generating facility, i.e., the county and state of the proposed generating facility, the electrical bus location(s), and the Local Resource Zone. MISO states that the ERAS interconnection request must identify the expected peak demand for electricity in MW over any one hour period and that the requested level of interconnection service must not exceed 150% of the identified MW need.

116. MISO states that it plans to publish an ERAS webpage that will include a significant amount of information related to each ERAS interconnection request.[289] MISO states that ERAS applications must include a non-confidential summary of the information contained in the interconnection requests for MISO to publish on its website. The summary will include the interconnection customer proposing the generating facility, the MW range of need that the ERAS interconnection request will address, the Local Resource Zone where the proposed generating facility will be located, and a general

---

[285] *Id.*; Witmeier Testimony at 45.

[286] Transmittal at 50.

[287] *Id.* at 59; Witmeier Testimony at 46.

[288] Transmittal at 34; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.3.1.

[289] Transmittal at 34; Witmeier Testimony at 38-39.

description of the driver for the load need (e.g., a data center, manufacturing plant, etc.).[290] MISO states that in addition to the non-confidential summary, it will publish the RERRA that submitted a verification for each ERAS interconnection request, the specific group that the ERAS interconnection request falls within (i.e., LSE, independent power producer, or retail choice), and the specific ERAS quarterly study period in which the ERAS interconnection request will be studied once MISO has completed the screening process for each ERAS quarterly study period. Finally, MISO states that it plans to publish an information guide for potential ERAS interconnection customers that addresses common questions and problems that prospective ERAS interconnection customers may face.[291] MISO states that these additional requirements will increase the transparency of the ERAS process.

b. Responsive Pleadings

i. Comments in Support

117. Commenters argue that the Revised ERAS Proposal maintains open access[292] and is not unduly discriminatory or preferential.[293] As evidence of this, commenters raise several points regarding the Revised ERAS Proposal, including: (1) there are ERAS slots reserved specifically for independent power producers;[294] (2) projects that do not meet ERAS requirements or are not identified by the RERRA as necessary for resource adequacy may still proceed through the DPP;[295] and (3) DPP interconnection requests can

[290] Transmittal at 34.

[291] *Id.* at 34-35.

[292] AECS Comments at 8; Big Rivers Electric Comments at 7; Consumers Energy Comments at 3; Entergy/Cleco/Cooperative Energy Comments at 13; ITC Comments at 5; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 19; Missouri Commission Comments at 3-4; NIPSCO Comments at 8; Texas Commission Comments at 12.

[293] AECS Comments at 8; Big Rivers Electric Comments at 7; Consumers Energy Comments at 3; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 17; Missouri Commission Comments at 3; NIPSCO Comments at 8; Texas Commission Comments at 9.

[294] AECS Comments at 8; Arkansas Commission Comments at 3; Big River Electric Comments at 8; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 13; MISO TOs Comments at 16-17.

[295] AECS Comments at 8.

transfer to ERAS.[296] Commenters also argue that ERAS is open to all project sponsors, and fuel and technology types, so long as the interconnection request satisfies the ERAS requirements.[297]

118. Commenters assert that with the revisions to require RERRA verification and the identification of a specific need in the same Local Resource Zone as the ERAS interconnection request, MISO's Revised ERAS Proposal is a just and reasonable solution to MISO's resource adequacy and reliability concerns.[298] Several commenters argue that the RERRA verification process reasonably balances MISO's need to verify projects that meet resource adequacy needs.[299] Further, Louisiana and Mississippi Commissions assert that the RERRA verification reasonably balances, "the state's need to not prejudge generation certifications."[300] Michigan Commission states that it supports MISO's proposed limit to study 10 interconnection requests per quarterly study period, the RERRA verification, and the other eligibility requirements for interconnection requests to participate in ERAS.[301] Michigan Commission adds that the executed agreement requirement provides a direct linkage from the resource adequacy need to the ERAS interconnection request.

119. Midwest TDUs state that they appreciate that the Revised ERAS Proposal will be implemented in a manner that allows municipal joint action agencies to meaningfully participate.[302] Midwest TDUs assert that joint action agencies can submit notifications as the documented representative of their municipal utility member RERRAs, consistent

---

[296] Big River Electric Comments at 8; Louisiana and Mississippi Commissions Comments at 8.

[297] AECS Comments at 8; Arkansas Commission Comments at 3; Big Rivers Electric Comments at 8; Consumers Energy Comments at 3; Entergy/Cleco/Cooperative Energy Comments at 13; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 17; NIPSCO Comments at 8.

[298] Big Rivers Electric Comments at 8; NIPSCO Comments at 7-8.

[299] Louisiana and Mississippi Commissions Comments at 10; Otter Tail Comments at 4; Texas Commission Comments at 8.

[300] Louisiana and Mississippi Commissions Comments at 10.

[301] Michigan Commission Protest at 7-9.

[302] Midwest TDUs Comments at 4.

with applicable laws and governance documents.[303] Midwest TDUs state that this provides assurance that they will not be foreclosed from, or unduly disadvantaged in, the ERAS process, which could be crucial to meeting their municipal utility members' resource adequacy and reliability needs.

120. Several commenters state that the Local Resource Zone requirement tightly ties the generating facility to the resource adequacy or reliability need.[304] Entergy, Cleco, and Cooperative Energy argue that the proposed requirement that resources be located in the same local resource zone as the associated resource adequacy or reliability need and the proposed limitation on the amount of interconnection service that may be requested through an ERAS interconnection request, providing reassurance that the ERAS interconnection requests studied by MISO will be limited to those that can meet anticipated generation capacity shortfalls.[305] AECS notes that the local resource zone requirement ensures that generating facilities can actually serve the load.[306]

121. Several commenters assert that the proposed cap on the number of ERAS interconnection requests that can studied for the entirety of the program and proposed cap on the number of interconnection requests that can be studied quarterly will better ensure that MISO studies interconnection requests in an accelerated time frame.[307] Commenters also note that the addition of a fixed "sunset date" ensures that ERAS is a temporary measure to address near-term resource adequacy needs.[308]

---

[303] *Id.* at 7.

[304] AECS Comments at 5; Entergy/Cleco/Cooperative Energy Comments at 12; Louisiana and Mississippi Commissions Comments at 9.

[305] Entergy/Cleco/Cooperative Energy Comments at 12-13.

[306] AECS Comments at 5-6.

[307] AECS Comments at 7; Arkansas Commission Comments at 3; Consumers Energy at 3; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 9; MISO TOs Comment at 14; NIPSCO Comments at 8; Ottertail Comments at 4-5; Texas Commission Comments at 9-11; Wisconsin Utilities Comments at 4.

[308] Entergy/Cleco/Cooperative Energy Comments at 10; Otter Tail Comments at 4.

ii. Protests

(a) RERRA Verification Requirement

122. Protesters assert that the proposed Tariff, similar to the Initial ERAS Proposal, continues to lack any objective or transparent criteria to be used for the RERRA verification process and that it is not clear what would justify MISO's acceptance or rejection of ERAS submissions.[309] Michigan Commission argues that absent minimal RTO/ISO-level guardrails against discriminatory treatment and favoritism of certain projects over others, each RERRA must attempt to run its own screening process with incomplete information and without assistance from the RTOs/ISOs.[310] EPSA similarly argues that the proposed RERRA verification process gives RERRAs "significant power to delay [independent power producer] ERAS projects – or block them entirely in favor of ERAS submissions from the LSE in their respective service territory."[311]

123. Invenergy requests that MISO provide clarification on various proposed Tariff provisions, including the GIP section 3.9.1(ii) provision to explain what constitutes "other processes" or which among the LSE, RERRA, or interconnection customer is responsible to determine the resource adequacy need.[312] Invenergy also requests that MISO clarify what constitutes an "other agreement" under the executed agreement requirement because, without clarity, a RERRA could decide on its own accord what type of agreement qualifies.[313] Invenergy also states that MISO should clarify whether an ERAS interconnection customer keeps its EGIA if the agreement with the off-taker falls through.

124. With respect to the RERRA verification and retail choice, Michigan Commission strongly urges the removal of the proposed Tariff language stating that the RERRA verification can be supported by "a state energy forecast, or other forward-looking forecast."[314] According to Michigan Commission, this Tariff provision, in addition to

---

[309] EPSA Comments at 3-4; Invenergy Protest at 3-5; Michigan Commission Protest at 11-12.

[310] Michigan Commission Protest at 11.

[311] EPSA Comments at 6.

[312] Constellation Protest at 6.

[313] Invenergy Protest at 7-8.

[314] Michigan Commission Protest at 16 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.1.ii.a).

being unnecessary, would allow nearly any project to be eligible for ERAS as long as there is some forecast to support it. Constellation argues that RERRAs are provided an unworkable and standardless veto power in retail choice states.[315]

125. Several protesters argue that the Revised ERAS Proposal, like the Initial ERAS Proposal before it, discriminates against independent power producers, and that additional time is required for independent power producers to meet the ERAS participation requirements.[316] Clean Grid Alliance argues that MISO's proposed carve out for independent power producers does not solve the discriminatory and preferential design of ERAS because MISO's proposal maintains its dependence on RERRA "validation."[317] Michigan Commission argues that the incumbent utilities' advantage over independent power producers results in inappropriately overburdening the RERRAs.[318] MISO IPPs assert that the Revised ERAS Proposal is distinguishable from the PJM RRI, which did not treat similarly situated interconnection customers differently.[319]

126. Vistra and COMPP assert that independent power producers contracting with customers other than LSEs will require additional time to meet the participation requirements compared to vertically integrated utilities in regulated states that already have participation documents and RERRA approvals in place.[320] According to Vistra, it will be extremely difficult for independent power producers to submit all required information and receive RERRA approval in the timeframe necessary to participate in the first ERAS quarterly study period, which begins on September 1, 2025. Vistra argues, among other things, that states are not similarly situated in their capacity to respond to the new verification requirements for independent power producer interconnection requests, and that it is possible that all 10 carve out slots are immediately filled by interconnection requests in the handful of states that are best positioned to implement the verification

---

[315] Constellation Protest at 5.

[316] Clean Energy Associations Protest at 13-16; Clean Energy Associations Docket No. ER25-1674 Protest at 22, 43-44; Clean Grid Alliance Protest at 25, 63, 70, 72-78; COMPP Protest at 8-9; EPSA Protest at 4-6; MISO IPPs Docket No. ER25-1674 Protest at 9; NextEra Docket No. ER25-1674 Protest at 15-17; PIOs Protest at 5-9; PIOs Docket No. ER25-1674 Protest at 9-10; Vistra Protest at 6, 9-11.

[317] Clean Grid Alliance Protest at 25.

[318] Michigan Commission Protest at 10-11.

[319] MISO IPPs Docket No. ER25-1674 Protest at 8 (citing Kelliher Aff. at 3).

[320] COMPP Protest at 8; Vistra Protest at 6.

requirements quickly.[321] Vistra and COMPP propose that the initial independent power producer carve out application window begin in alignment with the second study period, starting on December 1, 2025.[322] Alternatively, COMPP requests that MISO reserves at least two study slots for independent power producers per ERAS cycle starting in December 2025.[323]

127. Similarly, Clean Grid Alliance asserts that LSEs have long-standing relationships with RERRAs while independent power producers do not, and this provides LSEs with an advantage in accessing ERAS. Clean Grid Alliance contends that LSE interconnection requests and independent power producer interconnection requests are similarly situated but that MISO's proposed carve out is evidence that ERAS caters to LSE participation.[324] Clean Grid Alliance further contends that, if MISO intended for independent power producers and LSEs to compete on equal footing, it would allow an equal number of spots for independent power producer ERAS interconnection requests and LSE ERAS interconnection requests.[325]

128. EPSA argues that it is often not possible for retail choice LSEs to indicate the specific load it will serve due to the nature of their agreements that often supply loads through a portfolio approach.[326] EPSA also states that competitive retailers often undertake a "demonstration of need" for corporate risk and hedging purposes to compare existing and expected future contractual obligations to load with the physical positions and market exposure of the LSE.[327] Accordingly, EPSA argues that MISO should clarify that an interconnection request that asserts the need for physical hedging of risks through

---

[321] Vistra Protest at 10.

[322] *Id.* at 6, 9-11; COMPP Protest at 9.

[323] COMPP Protest at 9.

[324] Clean Energy Associations Docket No. ER25-1674 Protest at 17-18 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 12); Clean Grid Alliance Protest at 24-25, 74, 78 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 696); *see also* PIOs Docket No. ER25-1674 Protest at 9-10 (citing *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d at 684).

[325] Clean Grid Alliance Protest at 26.

[326] EPSA Comments at 8-9.

[327] *Id.*

the addition of a resource is sufficient to meet the forward-looking forecast option contemplated in the proposed Tariff language.

129. PIOs argue that the Revised ERAS Proposal's selection criteria may make it challenging for merchant generators to benefit from ERAS interconnection service. PIOs allege that the proposal's requirement for merchant generators, such as independent power producers seeking to serve retail choice markets, to indicate the specific load that the generating facility will serve, differs from the requirement in non-retail choice markets, where the only requirement is to have RERRA verification that the ERAS interconnection request will address a resource adequacy deficiency without identifying specific customers to be served.[328] PIOs explain that, for example, in Illinois, an independent power producer may sell capacity credits to different counterparties each year or sell into the planning resource auction, which supports resource adequacy; however, an independent power producer that intends to participate in these markets will not be able to benefit from ERAS. PIOs add that, in Michigan, there is a 10% cap on the total amount of customer load that may take supply under retail choice, which is currently met and has been for several years. PIOs state that the cap on retail choice load cannot be increased until a new load joins a utility's system, which could make it difficult for an independent power producer to contract with a new large load for retail choice before such load joins the transmission system. PIOs further explain that once a new load joins the transmission system and the cap is increased, interconnection customers already in the queue would have the first opportunity on supplying the load.

130. Clean Energy Associations state that the Commission previously rejected a proposal by Xcel Energy Operating Companies to expedite interconnection requests selected through a state-sponsored procurement process, finding that this would discriminate against customers that "are not part of the state-sponsored bidding process" and would provide transmission owners "the power to discriminate against non-affiliated generation projects."[329]

(b) ERAS Cap and Carve Outs

131. Several protesters argue that MISO's proposed cap and carve outs are arbitrary.[330] PIOs and Invenergy argue that MISO has failed to demonstrate how the proposed limit of

[328] PIOs Protest at 13-14.

[329] Clean Energy Associations Docket No. ER25-1674 Protest at 43-44 (citing *Xcel*, 106 FERC ¶ 61,260 at PP 21, 22).

[330] EPSA Protest at 7-8; Invenergy Protest at 13; PIOs Protest at 18-20; Vistra Protest at 8.

68 ERAS interconnection requests is tailored to ensure just and reasonable rates.[331] Several protesters also argue that MISO's proposed carve outs for independent power producers and retail choice loads are discriminatory.[332]

132. PIOs argue that MISO's proposed carve out of eight ERAS interconnection requests for retail choice load does not reduce discrimination for retail choice load in Illinois and Michigan.[333] PIOs argue that MISO has not demonstrated how eight interconnection requests is an equitable approximation of those customer bases' relative sizes and projected shortfalls. PIOs contend that not requiring RERRA approval in order for ERAS interconnection requests to move forward in retail choice markets may result in ERAS interconnection requests that are not well suited to meet the state's needs.[334] Further, PIOs assert that MISO's proposed 10-day window to allow the RERRA to veto an ERAS interconnection request in retail choice markets is not enough time for such RERRAs to adequately review the proposed interconnection request.

133. PIOs argue that MISO's Revised ERAS Proposal is also unduly discriminatory because it largely excludes independent power producers from the process.[335] PIOs state that while they agree that the proposed carve out of 10 ERAS interconnection requests for independent power producers without an LSE agreement lessens the discriminatory effect of ERAS somewhat, MISO's argument that the carve out provides independent power producers with comparable access to the ERAS process is not true. PIOs state that a truly non-discriminatory process would provide independent power producers with a fair opportunity to compete for 100% of the ERAS cap, rather than 15% of the cap with no support as to how the amount was determined. PIOs further claim that splitting a cap into smaller buckets for different types of interconnection customers does nothing to establish competition that can limit costs to consumers.

134. Invenergy argues that MISO's proposed carve out for independent power producers does not make participation easier for such entities because it does not alleviate the contracting challenges in MISO, which typically require an estimate of project costs

---

[331] Invenergy Protest at 13; PIOs Protest at 18.

[332] Clean Energy Associations Protest at 30-31; Clean Grid Alliance Protest at 26; COMPP Protest at 9; Constellation Protest at 6 (citing Transmittal at 25); EPSA Protest at 4-5; Illinois Commission Comments at 4-5; Invenergy Protest at 15-16; PIOs Protest at 5-6; Vistra Protest at 8, 12.

[333] PIOs Protest at 12-13.

[334] *Id.* at 13-14.

[335] *Id.* at 5-6.

before finalizing off-taker agreements.[336] Invenergy adds that MISO's requirement to contract with an LSE will raise consumer prices because contracts will be executed without knowing the full costs of a project, and such costs will be passed on to consumers.

135. Several protesters argue that the Tariff should be clarified to explain that independent power producers are eligible to participate in the initial 50 project tranche if those independent power producers are serving LSEs.[337] EPSA states that the proposed Tariff language, which states that there is a "maximum of" eight interconnection requests for retail choice load and 10 interconnection requests for independent power producers, does not properly reflect MISO's intent to allow independent power producers the opportunity to compete for the other 50 non-carve out slots.[338] Vistra suggests that the words "a maximum of" in GIP section 3.9.2 be struck and the language in GIP section 3.8.2 be clarified to reflect MISO's intent to reserve a minimum number of slots for eligible independent power producer interconnection requests to participate in ERAS, rather than to cap independent power producer project participation.[339] EPSA and COMPP similarly urge the Commission to require MISO to clarify the Tariff language.[340]

136. Clean Energy Associations argue that, in the case where an ERAS interconnection request overlaps with more than one carve out, MISO's proposed Tariff language is unclear as to whether a slot from both carve outs would be eliminated.[341] Similarly, PIOs argue that it is unclear whether an independent power producer in Michigan or Illinois with a supply agreement, not with an LSE, would qualify for the independent power producer or retail choice carve out under MISO's proposal.[342]

---

[336] Invenergy Protest at 15-16.

[337] *See, e.g.*, EPSA Protest at 4-5; Illinois Commission Comments at 4-5; Vistra Protest at 8, 12 (citing MISO, Proposed Tariff, attach. X (175.0.0), §§ 3.9.2, 3.8.2).

[338] EPSA Protest at 4 (citing Transmittal at 12); *see also* COMPP Protest at 9; Vistra Protest at 12.

[339] Vistra Protest at 12 (citing to MISO, Proposed Tariff, attach. X (175.0.0), §§ 3.9.2, 3.8.2).

[340] COMPP Protest at 9; EPSA Comments at 4-5.

[341] Clean Energy Associations Protest at 30.

[342] PIOs Protest at 15.

137. Clean Energy Associations also argue that it is unclear regarding whether independent power producers can compete on equitable terms for the remaining 50 spots in ERAS because MISO's proposed Tariff language is not clear on the types of agreements it will accept for the 50 slots.[343] Clean Energy Associations explains that the "other agreement" category for the executed agreement requirement suggests that independent power producers may have agreements with entities other than LSEs and asserts that MISO should clarify that such ERAS interconnection requests are not precluded from competing for the 50 slots.[344] Additionally, Illinois Commission states that MISO's proposed language in GIP section 3.9.2 is unclear as to whether "agreements with entities other than Load Serving Entities" is intended to mean large load end users such as data centers.[345]

(c) Other ERAS Eligibility Requirements

138. Several protesters argue that the Revised ERAS Proposal lacks stringent and objective eligibility criteria and differentiate the ERAS eligibility requirements from RTO/ISO generator interconnection proposals that the Commission has accepted.[346] For example, MISO IPPs argue that the CAISO IPE proposal's scoring criteria appropriately incorporated state and local regulatory authorities' interests, whereas ERAS fully delegates ERAS eligibility to RERRAs.[347] Similarly, MISO IPPs and Clean Energy Associations argue that the Commission found the PJM RRI proposal's specific scoring

[343] Clean Energy Associations Protest at 30.

[344] *Id.* at 31.

[345] Illinois Commission Comments at 5.

[346] Clean Energy Associations Docket No. ER25-1674 Protest at 43; Clean Grid Alliance Protest at 11,15; MISO IPPs Docket No. ER25-1674 Protest at 19-21 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at P 94); NextEra Docket No. ER25-1674 Protest at 24 (citing MISO, Tariff, attach. X (GIP) (171.0.0), §§ 3.6, 7.9.3).

[347] MISO IPPs Docket No. ER25-167 Protest at 20 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at P 123).

criteria in the tariff to be facially neutral,[348] while ERAS criteria are not facially neutral because RERRAs determine eligibility.[349]

139. Additionally, Clean Grid Alliance and NextEra contend that the ERAS financial requirements are not sufficiently stringent, conflict with MISO's recent queue reforms, and do not disincentivize speculative interconnection requests from joining ERAS.[350] NextEra argues that an interconnection customer could submit a speculative interconnection request into ERAS to determine its liability for network upgrades, withdraw after seeing the results, and receive a refund of all the fees paid minus the $100,000 D1 application fee and study costs. NextEra states that the prospect of losing $100,000 is unlikely to act as a material deterrent to the submission of speculative interconnection requests or a reliable indicator of the commercial viability of a project.[351] Clean Grid Alliance argues that the M2 payment in ERAS should be forfeited if the interconnection customer withdraws to deter speculative interconnection requests and minimize late stage restudies.[352]

140. Clean Energy Associations argue that the $100,000 D1 application fee discriminates against independent power producers.[353] Clean Energy Associations assert that, while LSEs can afford high up-front costs that they can pass along to ratepayers, independent power producers do not have this same ability, particularly in the early stages of development before they have secured financing. Clean Energy Associations argue that ERAS incents LSEs to submit interconnection requests to ERAS regardless of readiness because their ratepayers will likely bear the risk responsibility for delays, cost overruns, or stranded assets.

141. Clean Grid Alliance contends that MISO's lack of requirement for a financial security for affected system upgrades and other studies not completed by the execution of

---

[348] Clean Energy Associations Docket No. ER25-1674 Protest at 43; MISO IPPs Docket No. ER25-1674 Protest at 20 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 123).

[349] Clean Energy Associations Docket No. ER25-1674 Protest at 43; MISO IPPs Docket No. ER25-1674 Protest at 20.

[350] Clean Grid Alliance Protest at 11-12, 15; NextEra Docket No. ER25-1674 Protest at 25-26.

[351] NextEra Docket No. ER25-1674 Protest at 26.

[352] Clean Grid Alliance Protest at 80-81.

[353] Clean Energy Associations Docket No. ER25-1674 Protest at 19.

an EGIA is not stringent enough and may lead to late-stage withdrawals.[354] Clean Grid Alliance further contends that the Revised ERAS Proposal's lack of provisions to address potential ERAS restudies, based on an expectation that there will not be any, is a "gamble."[355]

142. Constellation argues that that the proposal appears to impose higher and unreasonable disclosure obligations on projects serving retail choice customers.[356] DTE Electric states that the Commission should clarify that the sunset provision in MISO's proposed Tariff language does not preclude it from revisiting the sunset date if circumstances require.[357]

143. NextEra asserts that the ERAS site control requirements are not more rigorous than those applied to DPP interconnection requests,[358] and even if they were, demonstrating 100% site control is insufficient to ensure that ERAS interconnection requests are "shovel ready," as other resources that demonstrate 100% site control still encounter challenges that delay commercial operation.[359] NextEra asserts that MISO did not propose objective criteria to ensure that interconnection requests are "shovel ready," and therefore there is no assurance that ERAS interconnection requests will not be delayed similarly to DPP interconnection requests.[360]

144. PIOs argue that MISO's proposed commercial operation date requirement fails to prevent preferential treatment towards ERAS interconnection requests, which may not

---

[354] Clean Grid Alliance Protest at 13.

[355] *Id.* at 13-14.

[356] Constellation Protest at 5-6.

[357] DTE Electric Comments at 5.

[358] NextEra Docket No. ER25-1674 Protest at 24-25 (citing MISO, Proposed Tariff, attach. X(GIP) (175.0.0), § 7.2.2.1(ii) (requiring customers to demonstrate 100% site control for all "Interconnection Customer's Facilities (including demonstration of switchyard site control if requested by the Transmission Provider), and, if applicable (i.e., when the Interconnection Customer is providing the site for such facilities), the Transmission Owner's Interconnection Facilities and Network Upgrades at the [Point of Interconnection] that the Interconnection Customer will develop")).

[359] NextEra Docket No. ER25-1674 Protest at 25 (citing Witmeier Rebuttal Testimony at 14).

[360] NextEra Protest at 25.

reach commercial operation for another eight years following MISO's filing.[361] PIOs also point out that MISO's commercial operation date requirements differ from those in PJM RRI, which required RRI projects to waive the one-year milestone extension provided for in PJM's generator interconnection process.[362]

(1) Executed Agreement Requirement

145. Several protesters argue that the executed agreement requirement unduly discriminates against different classes of interconnection customers. As evidence, they point out that pursuant to this executed agreement requirement, non-LSEs and other competitive generation developers must obtain an offtake agreement to qualify, while LSEs can simply voice an intention to self-supply.[363] Michigan Commission states that while the carve out for 10 independent power producer interconnection requests is helpful, incumbent utilities can self-supply while independent power producers must take an additional step of having an executed agreement or work with an LSE to meet a resource adequacy need.[364] Several protesters similarly assert that the requirement for independent power producers contracting with LSEs to submit an executed agreement to achieve the first stage of eligibility fails to provide access to independent power producers on a comparable and sufficiently non-discriminatory basis.[365] Several protesters assert that this is an additional, unfair burden that limits competitive independent power producers' viability in ERAS.[366] EPSA requests that the Commission require MISO to remove these requirements for independent power producers or, at a minimum, that the Commission delay the due date for ERAS submission for the independent power producer carve outs, which would allow time for MISO states to

[361] PIOs Protest at 25.

[362] *Id.* at 26 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 265).

[363] Clean Energy Associations Protest at 31; Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; Clean Grid Alliance Protest at 26-27, 75; MISO IPPs Docket No. ER25-2674 Protest at 12-13; NextEra Docket No. ER25-1674 Protest at 36-38; PIOs Protest at 5; PIOs Docket No. ER25-1674 Protest at 10-12.

[364] Michigan Commission Protest at 10.

[365] Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; EPSA Comments at 5; Invenergy Protest at 7; Michigan Commission Protest at 10; MISO IPPs Docket No. ER25-1674 Protest at 12-13; NextEra Docket No. ER25-1674 Protest at 37-38; PIOs Protest at 5; PIOs Docket No. ER25-1674 Protest at 11.

[366] Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; Clean Grid Alliance Protest at 61-62.

determine the RERRA verification process for independent power producer interconnection requests, and for all independent power producers to negotiate the required agreements and meaningfully participate in the ERAS process.[367] Invenergy argues that it is unclear how independent power producers may present contracts to RERRAs under MISO's proposal, particularly where some state laws prohibit interconnection customers from making requests to RERRAs.[368]

146. MISO IPPs, Clean Energy Associations, Clean Grid Alliance, PIOs, and NextEra assert that independent power producers and load typically execute agreements after receiving cost estimates to appropriately price the agreement before execution.[369] Accordingly, these entities argue that the Revised ERAS Proposal discriminates against non-LSEs because ERAS is either non-viable for non-LSEs or is more stringent than the self-supply acknowledgement.[370] Clean Energy Associations assert that because some network upgrade costs will not be known in time to execute a durable offtake agreement, this may harm reliability needs and could cause disruption without benefit, as purchasers would sign a PPA that may lead to over-procurement to avoid contract termination or dropping out of ERAS altogether.[371]

147. NextEra and PIOs contend that independent power producers may not be able to enter ERAS unless an LSE grants the independent power producer an agreement or otherwise cooperates with the independent power producer, which, in effect, allows LSEs to choose which resources qualify for ERAS.[372] NextEra asserts that the CAISO IPE proposal gave independent power producers realistic opportunities to obtain interconnection service, but that ERAS does not have any of the CAISO IPE proposal's

---

[367] EPSA Comments at 5-6.

[368] Invenergy Protest at 5.

[369] Clean Energy Associations Docket No. ER25-1674 Protest at 12, 49; Clean Grid Alliance Protest at 74-75; MISO IPPs Docket No. ER25-1674 Protest at 13; NextEra Docket No. ER25-1674 Protest at 36-37; PIOs Docket No. ER25-1674 Protest at 11-12.

[370] Clean Energy Associations Protest at 13-16; Clean Grid Alliance Protest at 61-62; MISO IPPs Docket No. ER25-1674 Protest at 13; NextEra Docket No. ER25-1674 Protest at 36-37.

[371] Clean Energy Associations Docket No. ER25-1674 Protest at 13-15.

[372] NextEra Docket No. ER25-1674 Protest at 38; PIOs Docket No. ER25-1674 Protest at 10.

guardrails to ensure no undue discrimination against independent power producers.[373] Additionally, NextEra asserts that the risk of undue discrimination is exacerbated by ERAS allowing some entities, like cooperatives, to be both LSEs and RERRAs, which may incentivize the entity to prevent independent power producers from obtaining access to ERAS to protect the competitive advantage of its resources.[374] NextEra asserts that the Commission has historically rejected proposals that disadvantage independent power producers and other non-incumbents, citing to a PacifiCorp proposal that had different commercial readiness demonstration options for LSEs and independent power producers[375] and a Public Service Company of Colorado proposal that had commercial readiness criteria that were "likely too stringent for independent power producers to meet."[376] NextEra further asserts that, in Order No. 2023, the Commission declined to adopt requirements and criteria for demonstrating commercial readiness by submitting an executed term sheet or an executed PPA because these "may not be workable in markets where merchant sales are common."[377]

148. Clean Grid Alliance argues that independent power producers do not have access to information about load that "meet[s] an identified resource adequacy and/or reliability need," either at all or at the same time/level as LSEs.[378] Clean Grid Alliance also argues that the ERAS proposal will send the wrong market signals and stifle competition because it denies independent power producers' meaningful participation and restricts competition.[379]

149. Clean Grid Alliance further argues that ERAS unduly preferences LSEs because an LSE can submit an expedited process review as an exception to the standard MISO Transmission Expansion Plan (MTEP) process to include transmission to serve such spot load, which may make obtaining a RERRA certification easier, while an independent

---

[373] NextEra Docket No. ER25-1674 Protest at 39 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at PP 174, 176).

[374] *Id.* at 38.

[375] *Id.* at 34 (citing *PacifiCorp*, 171 FERC ¶ 61,112, at PP 68-69 (2020)).

[376] *Id.* at 35 (citing *Pub. Serv. Co. of Colo.*, 183 FERC ¶ 61,166, at P 65 (2023) (*PSCo*)).

[377] *Id.* at 35-36 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 614-615, 696-98).

[378] Clean Grid Alliance Protest at 73.

[379] *Id.* at 61-62.

power producer cannot.[380] Additionally, Clean Grid Alliance contends that independent power producers will face greater barriers to exit the DPP due to the withdrawal penalties than LSEs, which have a safety net with costs backstopped through the state public utility commission.[381] Accordingly, protesters assert that the executed agreement requirement in ERAS is an additional, unfair burden that limits competitive independent power producers' viability.

(2) Local Resource Zone

150. PIOs argue that MISO's proposed requirement that an ERAS interconnection request must be located within the same Local Resource Zone as the load it will serve, unless the project was included in a resource filing or other submission to the RERRA, adds another element of discrimination.[382] Invenergy argues that the proposed Local Resource Zone requirement artificially constrains the number of eligible interconnection requests that might be suited to serve a resource adequacy need.[383]

151. PIOs further argue that the structural differences in relationship with the RERRA for independent power producers compared to LSEs will make it significantly harder for independent power producers to ensure that a project located outside of a Local Resource Zone is included in a resource filing or submission before the RERRA.[384] Relatedly, Constellation argues that it is "beyond dispute" that a generating facility in one Local Resource Zone can serve load in another, and it is therefore unduly discriminatory for MISO to propose excluding an interconnection request for consideration in ERAS simply because the proposed generating facility is located in a different Local Resource Zone.[385] Constellation asserts that MISO's proposed exception in this respect does not change that. Further, Constellation argues that MISO has not explained what "resource filing or other submission made to the RERRA" would satisfy this requirement, particularly in retail choice states.

---

[380] *Id.* at 73-74.

[381] *Id.* at 79.

[382] PIOs Protest at 9.

[383] Invenergy Protest at 12.

[384] PIOs Protest at 9.

[385] Constellation Protest at 7.

(3) Requested Interconnection Service May Not Exceed 150% of Identified Need

152. Michigan Commission and PIOs argue that, by capping interconnection requests at 150% of the identified need, the Revised ERAS Proposal effectively excludes renewable energy project participation and unfairly tilts the scales in favor of thermal generation.[386] PIOs explain that any new generation resource seeking interconnection needs interconnection service that matches its nameplate capacity, or it will be forced to curtail its output regularly.[387] PIOs argue that, as a result, ERAS effectively eliminates any resource receiving less than 67% capacity accreditation because such resources would have to request interconnection service in excess of 150% of the identified MW need to match the nameplate capacity.[388] PIOs further argue that MISO fails to engage with the fact that wind and solar resources receive significantly lower accreditation than other generation facility types and will therefore be uniquely impacted.[389] PIOs add that data presented at recent stakeholder meetings demonstrate that accredited values for renewable generation fell below 67%.[390] PIOs assert that MISO's discriminatory approach in the ERAS process cannot be justified because it is not tailored to meet MISO's stated resource adequacy and reliability needs.

153. Michigan Commission contends that the Initial ERAS Proposal, which capped interconnection requests at 125% of identified need and based the requirement on accredited capacity, instead of interconnection service, had a closer link to resource adequacy needs and was more equitable across fuel types. Michigan Commission asserts that in the alternative, if the amount remains based on interconnection service, the cap

---

[386] Michigan Commission Protest at 14-15; PIOs Protest at 10-11.

[387] PIOs Protest at 10.

[388] *Id*. PIOs further explain that, for example, "To meet a resource adequacy need of 100 MW, a resource with, e.g., 50% capacity accreditation would need to build to 200 MW of nameplate capacity, but Interconnection Service at that level would exceed MISO's proposed 150% limit." *Id*.

[389] *Id.* at 11.

[390] *Id.* (citing MISO, Resource Adequacy Subcommittee (RASC), *LOLE Modeling Enhancements Storage Modeling* 19 (Apr. 9, 2025), https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20St orage%20Modeling689245.pdf (using "even loss" values pursuant to MISO's proposed modeling approach in that presentation)).

should be raised to 200% to allow for renewable projects to participate and assuage discriminatory concerns.[391]

154. Clean Energy Associations also argue that the new requirement that the amount of interconnection service requested must not exceed 150% of the identified MW need will functionally cap intermittent resources and does not better link the claimed resource adequacy need and the proposed interconnection request, contrary to MISO's claim.[392]

iii. Answers

(a) MISO Answer

155. MISO states that it started with a base of 50 interconnection requests similar to the PJM RRI but ultimately proposed additional carve outs for 10 independent power producer interconnection requests and eight retail choice interconnection requests to reflect its unique environment that includes two retail choice states.[393] MISO argues that this cap, along with the 10 interconnection request limit per ERAS quarterly study period, will enable MISO to work efficiently on both ERAS and DPP studies. MISO explains that it determined a cap of eight interconnection requests for retail choice states based on internal analysis and discussion with retail choice states.[394] MISO asserts that a cap of eight interconnection requests for retail choice states strikes the right balance to proportionately allocate interconnection requests to retail choice states, based on the portion of MISO's footprint that those states represent.[395] MISO clarifies that the two carve outs are separate.

156. In response to protests that the 10-day RERRA review period is insufficient, MISO states that the 10-day timeframe, which was originally agreed to by stakeholders, is not intended to be a comprehensive review of the interconnection requests.[396]

157. MISO further clarifies, in response to Constellation, that the Revised ERAS Proposal does not impose higher obligations on interconnection requests serving retail

---

[391] Michigan Commission Protest at 15.

[392] Clean Energy Associations Docket No. ER25-1674 Protest at 10.

[393] MISO Answer at 13-14.

[394] *Id.* at 15.

[395] *Id.* (citing Witmeier Testimony at 37).

[396] *Id.* at 16.

choice customers.[397] MISO states that it is requiring the same non-confidential information from all ERAS interconnection requests and has created a process to allow interconnection customers serving retail choice customers to participate in ERAS. MISO further states that while it recognizes that retail load in Michigan is already fully provided for, it cannot require the states to serve resource adequacy needs in certain ways and is simply providing a tool for states with resource adequacy needs.[398]

158. MISO asserts that the purpose of the independent power producer carve out is to address claims that LSEs could block independent power producers from participating in the ERAS process.[399] MISO clarifies that independent power producers may also submit interconnection requests in the remaining group of 50 ERAS interconnection requests so that the independent power producer carve out functions as a guaranteed floor of 10 independent power producer-only interconnection requests. MISO answers that it opposes a delay in the due date for ERAS submission for the independent power producer carve out because it is impractical and administratively burdensome.[400]

159. MISO asserts that a ranking or scoring process is not appropriate because MISO does not believe that it should prescribe to a state or RERRA which interconnection requests should be selected.[401] MISO states that a state or RERRA can implement their own scoring or ranking criteria, but it is ultimately the state's role, not MISO's, to determine the resources that will be utilized in their jurisdiction due to the unique jurisdictional divide under the FPA. Thus, MISO states that it will not specify a state process, regardless of protesters' arguments that doing so would be more transparent or otherwise preferable.

160. MISO contends that the new RERRA verification requirement provides states and RERRAs with different regulatory review processes necessary flexibility and does not supplant these review processes.[402] MISO states that an interconnection request approved to participate in ERAS must still receive approval through the state's corresponding regulatory review process, thus ensuring that the RERRA verification does not pre-determine any outcome of an applicable state process. MISO further asserts that it cannot

---

[397] *Id.* at 17.

[398] *Id.* at 18.

[399] *Id.* at 19.

[400] *Id.* at 20.

[401] *Id.* at 24-25.

[402] *Id.* (citing Transmittal at 31; MISO Proposed Tariff, attach. X (GIP), § 3.9.1).

and should not mandate a set review process with pre-determined characteristics that supplant the RERRA's determinations with its own. MISO believes that RERRAs are the appropriate entity to select ERAS participants, especially with the Revised ERAS Proposal's guardrails. MISO disagrees with protesters that RERRAs will be incentivized to provide a verification for certain interconnection requests because the interconnection requests would need to receive approval through a full state review process. Finally, MISO states that the Revised ERAS Proposal balances respect for states' jurisdictions over their own resource mixes with requiring sufficient information and verification from the RERRA that the proposed interconnection requests is appropriate for ERAS.[403]

161. In response to Michigan Commission's opposition to a RERRA verification relying on a state energy forecast or other forward-looking forecast as support, and its contention that this is too broad as to allow nearly any interconnection request to qualify, MISO argues that it believes that it is a RERRA's prerogative to determine what supporting information to utilize.[404] MISO further argues that it believes that it is not appropriate for one state to dictate the supporting information that another state uses. MISO further explains that it is not the resource planner for the states within its footprint, and the RERRA verification requirement will tighten the nexus between the proposed ERAS interconnection request and an identified resource adequacy and/or reliability need. MISO additionally contends that the Local Resource Zone requirement will tighten the nexus between the RERRA-verified interconnection request and the resource adequacy need.[405] MISO asserts that the RERRA verification and executed agreement requirements provide strong evidence that an interconnection request's output will be used by the designated load.

162. In response to protesters' arguments regarding *Xcel*, MISO states that the Commission determined that the process in that case was unduly discriminatory because it excluded interconnection customers that did not participate in the state-sponsored bidding process.[406] MISO contends that this is not the case with the ERAS process because it is open to all applicants, not just those involved in a state solicitation process.

163. MISO states that the arguments that LSEs will exert undue influence over which resources qualify for ERAS by refusing to enter into agreements with competing

---

[403] *Id.* at 25-26.

[404] *Id.* at 24.

[405] *Id.* at 26-27 (citing Tab A, (Witmeier Docket No. ER25-1674 Rebuttal Testimony, at 10).

[406] MISO Docket No. ER25-1674 Answer at 16-17 (citing *Xcel*, 106 FERC ¶ 61,260 at P 22).

interconnection customers assumes counterintuitive behavior from LSEs and load drivers that should reasonably select the most preferable project option.[407] MISO argues that ERAS does not require nor encourage the selection of an LSE's project over another equally beneficial project, and regardless, the executed agreement requirement will severely limit the possibility of this occurring. MISO also contends that while LSEs that own generation may self-supply, they still must receive approval from the RERRA.[408] Additionally, MISO states that any disadvantage experienced by independent power producers in this competition is not a result of ERAS.[409] MISO also notes that ERAS is not intended to work for the majority of interconnection requests but to be a unique, time-limited process for "shovel ready" projects to address near-term load needs.[410]

164. MISO argues that, contrary to protester assertions, the ERAS process is intended to be complementary to the state regulatory review process that ensures that projects are necessary, cost-effective, and in the public interest.[411] MISO further clarifies that while an interconnection request must include a RERRA verification to participate in ERAS, that does not guarantee acceptance into ERAS, and the other eligibility requirements will ensure that an interconnection request is "shovel ready."[412]

165. MISO states that while it considered a scoring approach, it ultimately determined that because of MISO's composition, states should be left to determine their own resource adequacy needs.[413] MISO additionally states that ERAS does not need scoring criteria because its strict eligibility requirements ensure that only projects that are truly commercially ready can participate.[414]

166. In response to concerns that the executed agreement requirement is unduly discriminatory toward independent power producers, MISO states that ERAS is structured to encourage negotiation and agreement to occur earlier in the planning

---

[407] *Id.* at 25.

[408] *Id.* at 28.

[409] *Id.* at 25.

[410] *Id.* at 27.

[411] *Id.* at 18.

[412] *Id.* at 19.

[413] *Id.* at 31.

[414] *Id.* at 32.

process. MISO states that it has found that DPP interconnection customers without PPAs cited the lack of a PPA as the reason for their commercial operation date delay. MISO also states that it permits flexibility by not requiring detail in these agreements beyond that they will meet the load's identified resource adequacy need.[415]

167. MISO clarifies that it limited ERAS interconnection requests to 150% of the identified need based on the MW of interconnection service requested, not based on nameplate or accredited capacity.[416] MISO asserts that ERAS is focused on interconnection service rather than accredited capacity because it is resource neutral and only focused on "shovel ready" projects.[417]

168. In addition, MISO provides several clarifications regarding the purpose and use of proposed ERAS fees, milestones, and payments. MISO explains that, if an ERAS application is deemed ineligible, the non-refundable D1 application fee will be used for costs related to managing the ERAS process and that the application fee also serves to ensure only "shovel ready" projects are submitted.[418] MISO also clarifies that, with regard to proposed GIP provisions specifying that ERAS interconnection customers are eligible for a refund of the "remaining" M2 milestone upon withdrawal after GIA execution, the remaining M2 milestone would be what remains after meeting the initial milestone payment and/or the network upgrade costs memorialized in the EGIA.[419] MISO explains that any refund of the M2 milestone after GIA execution assumes that either the interconnection request did not result in network upgrades or that those network upgrades were less than the M2 milestone. In addition, MISO explains that an ERAS interconnection customer is liable for the network upgrade costs regardless of whether those costs are covered by the initial payment requirement under the EGIA or financial security rules. MISO reiterates that ERAS interconnection customers are responsible for any remaining network upgrade costs documented in the EGIA, and any corresponding facilities construction agreements or multi-party facilities construction agreements, even if the ERAS interconnection customer withdraws after EGIA execution.[420] Finally, MISO explains that, regarding whether transfer of ownership of

---

[415] *Id.* at 28-29.

[416] MISO Answer at 28.

[417] *Id.* at 28-29.

[418] *Id.* at Tab B, MISO Supplemental Answer, Docket No. ER25-1674-000 (filed Apr. 29, 2025), at 3 (MISO Docket No. ER25-1674 Supplemental Answer).

[419] MISO Docket No. ER25-1674 Supplemental Answer at 6.

[420] *Id.* at 7 (citing MISO, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.6.3).

ERAS projects after EGIA execution also transfers the load obligation, the commercial terms to address project transfer are outside the scope of the ERAS process.

(b) Additional Answers

169. In response to MISO's answer, Clean Grid Alliance argues that the ERAS process, unlike the DPP, is not an open or non-discriminatory process.[421] Instead, Clean Grid Alliance argues that the ERAS process makes LSEs, which "have an incentive to favor their own generation a gatekeeper for new generation."[422] Clean Grid Alliance further contends that FPA section 205 requires MISO to affirmatively demonstrate that its proposal is not unduly discriminatory and will not result in the unintended consequences discussed by protesters.[423] Clean Grid Alliance asserts that attempts to distinguish *Xcel* are unconvincing because the unduly discriminatory outcome that the Commission rejected there, where "Interconnection Customers that [did] not take part in . . . state-sponsored bidding [could not] compete . . . on an equal footing"[424] is "akin to" that presented by the ERAS proposal.[425] More specifically, Clean Grid Alliance claims that the executed agreement requirement, which requires "*some* kind of agreement in place with an LSE," prevents independent power producers from competing with LSEs on equal footing.[426] Clean Energy Alliance further avers that Order No. 2003 makes clear that the Commission should not approve deviations from its *pro forma* LGIP that provide "the mere opportunity for LSE (transmission owner) preference" and that the opportunity for undue discrimination is intrinsic to the ERAS proposal.[427]

170. Further, Clean Grid Alliance argues that MISO fails to support its claim that it worked closely with states to ensure that independent power producers have comparable

---

[421] Clean Grid Alliance Docket No. ER25-1674 Answer at 3-4.

[422] *Id.*

[423] *Id.* at 4 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,247, at P 77 (2016)).

[424] *Id.* at 5 (citing *Xcel*, 106 FERC ¶ 61,260 at P 23).

[425] Clean Grid Alliance Docket No. ER25-1674 Answer at 5.

[426] *Id.* at 5-6 (quoting MISO Docket No. ER25-1674 Answer at 25 (emphasis in original)).

[427] *Id.* at 6 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 696).

ability to participate in the ERAS process.[428] Additionally, Clean Grid Alliance asserts that it has cited "ample" precedent to support a finding that LSEs have an incentive to favor their own generation.[429] Clean Grid Alliance claims that the ERAS proposal is unduly discriminatory by providing an "exclusive preferential fast track for priority access to transmission headroom over DPP project to RERRA-anointed projects."[430] To this point, Clean Grid Alliance contends that ERAS interconnection requests enjoy penalty-free withdrawal during the study process, an advantage over DPP interconnection requests, and that relaxing DPP rules conflicts with MISO's claim that ERAS interconnection requests are "shovel ready." Further, Clean Grid Alliance argues that there is undue preference with respect to the ERAS power flow study dispatch over the DPP power flow study dispatch that "significantly lowers" the cost of interconnection for ERAS interconnection requests.[431]

171. Clean Grid Alliance asserts that MISO has not justified the proposed cap of 68 interconnection requests to be studied in ERAS. Specifically, Clean Grid Alliance avers that MISO's statement that it chose to cap LSE ERAS interconnection requests at 50, because that was the cap for the PJM RRI, is unreasonable because MISO has different resource needs than PJM and, further, that ERAS does not resemble the PJM RRI construct.[432]

172. Additionally, Clean Grid Alliance asserts that MISO does not justify allocating only 10 interconnection requests to independent power producers when LSEs have nearly unfettered access to the bulk of the ERAS interconnection request slots, to which LSEs can impose barriers to independent power producers' access.[433] Clean Grid Alliance asserts that RERRAs will not be able to verify ERAS interconnection requests submitted by independent power producers over those submitted by LSEs because LSEs will be able to deny agreements to independent power producers and reserve the 50 ERAS interconnection request slots for their own ERAS interconnection requests. Clean Grid Alliance avers that this is unduly discriminatory and preferential because independent

---

[428] *Id.* at 7.

[429] *Id.* at 8 (citing *Nat. Ass'n of Reg. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1279 (D.C. Cir. 2007); *Xcel Energy Servs., Inc. v. FERC*, 41 F.4th 548, at 561 (D.C. Cir. 2022)).

[430] *Id.* at 8-9.

[431] *Id.* at 9-10.

[432] Clean Grid Alliance First Answer at 10.

[433] *Id*. at 13-14.

power producers and LSEs are similarly situated because both entities seek to develop generation to serve load. Clean Grid Alliance adds that an LSEs' obligation to serve does not justify the undue discrimination created by the Revised ERAS Proposal.[434]

173. Clean Grid Alliance argues that, due to the reliability gaps resulting from MISO's proposed study modeling approach, the Revised ERAS Proposal conflicts with open access principles.[435]

174. MISO IPPs argue that the Commission cannot assume that there will be no undue discrimination or preference, or rely on RERRAs to see to that outcome, when MISO's Tariff language does not provide a reasoned basis for concluding that MISO has guarded against undue discrimination or preference.[436] MISO IPPs state that MISO's answer incorrectly defends that undue discrimination or preference as either a necessary feature or a harmless byproduct of its regulatory model.[437] More specifically, MISO IPPs argue that this proceeding is about interconnection service, which is within the Commission's exclusive jurisdiction under the FPA, and that the Commission is obligated to prevent undue discrimination or preference within its jurisdiction regardless of the MISO state's role in maintaining resource adequacy.[438] MISO IPPs also state that MISO's valid resource adequacy needs are a non-sequitur that does not excuse a violation of the statutory prohibition on treating similarly situated entities differently.[439] MISO IPPs aver that MISO's suggestion that RERRAs would not engage in discriminatory or preferential behavior because each ERAS project will still require state permits is not enough to meet MISO's burden under FPA section 205.[440]

175. MISO IPPs also state that the proposed carve out for 10 ERAS interconnection requests that may be submitted by independent power producers is unjustified and unduly discriminatory. MISO IPPs argue that MISO's answer, which states that independent power producers can also compete with the general group of 50 ERAS interconnection requests, does not resolve the undue discrimination concerns with the Revised ERAS

---

[434] Clean Grid Alliance Docket No. ER25-1674 Answer at 14.

[435] Clean Grid Alliance First Answer at 8.

[436] MISO IPPs Answer at 4.

[437] *Id.* at 5.

[438] *Id.* at 5-7.

[439] *Id.* at 7-8.

[440] *Id.* at 8 (citing MISO Answer at 25).

Proposal's cap and carve outs because the 50 slots allotted for LSEs will be controlled by vertically integrated utilities.[441] MISO IPPs argue that MISO has not justified why LSEs should have five times as many slots to submit ERAS interconnection requests.[442]

176. MISO IPPs argue that the Local Resource Zone requirement is unduly discriminatory. Specifically, MISO IPPs argue that the proposed requirement that an ERAS interconnection request only be included in an integrated resource plan filing, instead of approved by a RERRA, is not relevant to the determination of whether the interconnection request is better situated than others to meet the resource adequacy or reliably need in question.[443] MISO IPPs aver that this requirement is susceptible to gaming by LSEs that can adjust their integrated resource plan filings.[444] MISO IPPs further argue that MISO's answer does not explain how the Local Resource Zone requirement will address import-export concerns simply because the interconnection request is proposed in an integrated resource plan.[445]

177. Clean Energy Associations assert that the extent to which MISO will permit independent power producers to compete on equitable terms for the remaining 50 ERAS interconnection request spots remains unresolved by MISO's answer.[446] Clean Energy Associations state that MISO clarifies that, although independent power producers can compete for the 50 ERAS interconnection request spots, "projects submitted by [independent power producers] without LSEs are maxed out at 10 projects."[447] Clean Energy Associations assert that MISO's interpretation does not align with the plain language of the Tariff because the proposed Tariff language does not state that an entity must be an LSE to be eligible to compete for the 50 ERAS interconnection request spots.[448]

---

[441] *Id.* at 9-10 (citing MISO Answer at 19).

[442] *Id.* at 10.

[443] *Id.* at 12.

[444] *Id.*

[445] *Id.* (citing MISO Answer at 27).

[446] Clean Energy Associations Answer at 5-6 (citing Clean Energy Associations Protest at 30).

[447] *Id.* at 6 (citing MISO Answer at 19).

[448] *Id.* at 6-7 (citing MISO, Proposed Tariff, attach. X (175.0.0), § 3.9.1(2)(b)).

178. Clean Energy Associations argue that the 10 ERAS interconnection request carve out for independent power producers without an LSE contract is a permission structure for discrimination that contradicts well-established open access principles.[449] Clean Energy Associations assert that, under MISO's interpretation of the Tariff language, independent power producer interconnection requests will be at a disadvantage relative to LSE-owned or affiliated interconnection requests because the requirement to have a contract with an LSE puts the LSE in a gatekeeper role.[450] Furthermore, Clean Energy Associations argue that, by requiring that ERAS generating facilities must serve new load not accounted for in a resource plan or address a resource adequacy deficiency, independent power producers will be at an additional disadvantage because only the RERRA and LSE are likely to know what new load is unaccounted for in a resource plan.[451] Clean Energy Associations assert that the disadvantage faced by independent power producer interconnection requests relative to LSE-owned or affiliated interconnection requests results in a failure by MISO to address the preferential treatment for LSE projects and undue discrimination against independent power producer projects without LSE involvement.[452]

179. Clean Energy Associations contend that MISO's answer did not sufficiently respond to their claim that the 150% nameplate cap would only allow thermal resources to participate in ERAS; rather, MISO merely stated that its approach is resource neutral.[453] Clean Energy Associations assert that MISO ignores that the eligibility of planning resources to provide resource adequacy benefits depend on interconnection service in addition to capacity accreditation. Accordingly, Clean Energy Associations assert that, while remaining facially neutral as to which resources request it, the 150% limitation will operate as a functional bar on certain resources meeting an identified need. Clean Energy Associations argues that this approach will likely prevent non-thermal resources from being considered to meet identified needs because RERRAs and project sponsors are unlikely to consider solutions that would leave a substantial amount of capacity unstudied and incapable of being delivered.[454]

---

[449] *Id.* at 8.

[450] *Id.* at 7 (citing Clean Energy Associations Protest at 27-30).

[451] *Id.* (citing Clean Energy Associations Protest at 14).

[452] Clean Energy Associations Answer at 7.

[453] *Id.* at 10 (citing MISO Answer at 29).

[454] *Id.* at 11.

180. PIOs argue that MISO's proposal requiring an ERAS interconnection customer to request interconnection service of no more than 150% of the identified need discriminates against renewable generating resources because it would require such resources to interconnect at a level that prevents them from full economic dispatch. PIOs further argue that this is true even if a renewable generator is paired with battery storage, which PIOs allege would become a prerequisite for renewable generators' participation in ERAS in practice. PIOs contend that this requirement would result in renewable generators being limited in their ability to fully participate in times of increased demand and could impact utilities' future resource planning if renewable generators are limited in their output.[455]

181. PIOs argue that MISO's answer does not address PIOs' concern regarding the adequacy of oversight for the RERRA verification requirement.[456] PIOs contend that MISO did not make meaningful changes to the RERRA role in the Revised ERAS Proposal compared to the Initial ERAS Proposal.[457] PIOs further contend that, in its answer, MISO continues to refuse the adoption of any standard for the RERRA verification to explain how it weighs the merits of similarly situated interconnection requests for participation in ERAS, despite concerns raised by protesters and in Commissioner See's concurrence.[458] PIOs argue that the Revised ERAS Proposal may create reliance on a state or other forward-looking energy forecast as a supporting factor.[459] PIOs further argue that, as the Michigan Commission notes, this aspect of MISO's proposal would allow any interconnection request to be eligible for ERAS as long as a forecast supports it. PIOs contend that, as a result, utility-funded analyses could be utilized to support such forecasts with no quality standards in place. PIOs assert that MISO's inclusion of "other forward-looking forecast" in its Tariff obliges MISO to accept a RERRA verification based on such a forecast.[460]

---

[455] PIOs Answer at 7.

[456] *Id.* at 9.

[457] *Id.* at 10.

[458] *Id.* at 10-11 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1).

[459] *Id.* at 12.

[460] *Id.* (citing 18 C.F.R. § 35.1(e) (2024) ("No public utility shall, directly or indirectly, demand, charge, collect or receive any rate, charge or compensation for or in connection with electric service subject to the jurisdiction of the Commission, or impose any classification, practice, rule, regulation or contract with respect thereto, which is different from that provided in a rate schedule required to be on file with this

iv. Supplemental Answers

(a) MISO Supplemental Answer

182. MISO states that it intends for independent power producers to be able to compete for the 50 ERAS interconnection request spots regardless of whether the independent power producer's proposed interconnection request includes an agreement with an LSE.[461] MISO states that each of the proposed carve out groups are separate from each other and independent power producers may submit interconnection requests in each group.[462] MISO states that independent power producers without agreements with LSEs that submit interconnection requests to ERAS will first be counted towards the 10 independent power producer-only ERAS interconnection request carve out before being counted to the 50 ERAS interconnection request slots shared with LSEs serving non-retail choice loads.[463]

183. MISO states that the Revised ERAS Proposal is crafted to ensure that all interconnection customers can submit interconnection requests to ERAS for all states in the MISO footprint.[464] MISO explains that the carve out for independent power producers provides a safety net for independent power producers to ensure that they have access to at least 10 spots. MISO further explains that it adopted this carve out in the Revised ERAS Proposal to address stakeholder concerns that independent power producers could be precluded from participating in ERAS by LSEs fully subscribing the cap before independent power producers could submit their interconnection requests or by LSEs refusing to execute agreements with independent power producers.

184. MISO acknowledges that some commenters continue to interpret the proposed Tariff language in GIP section 3.9.2 as capping the number of ERAS interconnection requests that may be submitted by independent power producers, that do not have an agreement with an LSE, to 10. Therefore, MISO states that it would welcome a

---

Commission unless otherwise specifically provided by order of the Commission for good cause shown.")).

[461] MISO Supplemental Answer at 3.

[462] *Id*. MISO also clarifies that ERAS interconnection requests addressing retail choice loads may only apply for the retail choice carve out regardless of the entity submitting the interconnection request.

[463] *Id.* at 4.

[464] *Id.*

compliance directive from the Commission requiring MISO to include in its GIP section 3.9.2, in relevant part, the following clarifying revisions:[465]

> The Transmission Provider will evaluate Expedited Resource Addition Study requests in the order in which they are submitted using the time stamp from submission. The Transmission Provider will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the sunset date noted in Section 3.9.9. The Transmission Provider has carved out a maximum of 8 Interconnection Requests of the total 68 Interconnection Requests that may be submitted in accordance with 3.9.1.1(iii) to serve retail choice load and ~~a maximum of~~ 10 Interconnection Requests of the total 68 Interconnection Requests that may be submitted by Independent Power Producers (IPPs) with agreements with entities other than Load Serving Entities to ERAS until the sunset date noted in Section 3.9.9. The remaining 50 Interconnection Requests of the total 68 Interconnection Requests may be submitted by IPPs or Load Serving Entities (LSEs) to serve non-retail choice load. Interconnection Requests submitted by IPPs with agreements with entities other than LSEs to ERAS will be counted first towards the 10 Interconnection Requests cap of the total 68 Interconnection Requests before the 50 Interconnection Requests to serve non-retail choice load. After the 10 Interconnection Requests submitted by IPPs with agreements with entities other than LSEs are accepted by the Transmission Provider, any subsequent Interconnection Request submitted by IPPs will count toward the remaining 50 Interconnection Requests to serve non-retail choice load.[466]

(b) Additional Supplemental Answers

185. Vistra states that it supports MISO's proposed Tariff language regarding the carve out for independent power producer interconnection requests and asserts that the Commission should direct MISO to adopt such language on compliance. However, Vistra reiterates its argument that the timeline for independent power producers contracting with non-LSEs is too aggressive for such independent power producers to meaningfully participate in ERAS. Specifically, Vistra states that independent power producers contracting with non-LSEs would have to obtain an executed agreement and a RERRA verification by August 11, 2025, which is only days after the requested effective

[465] The strikeout text represents MISO's proposed deletions while the underlined text represents MISO's proposed additions.

[466] MISO Supplemental Answer at 5-6.

date for the instant filing.[467] Vistra contends that this timeline will result in the ten ERAS interconnection spots for independent power producers contracting with non-LSEs to be immediately filled by projects in states that can provide RERRA verifications immediately or by smaller projects that can complete applications quickly.[468] Vistra argues that MISO provides no explanation for its position that extending the timeline for independent power producers contracting with non-LSEs is impractical and burdensome.[469] Vistra further argues that adjusting the timeline would have no effect on the other categories of ERAS interconnection requests or the overall pace of ERAS and that adjusting the timeline would make ERAS more effective.[470]

186. Clean Grid Alliance argues that the MISO Supplemental Answer and proposed Tariff language demonstrates that the Revised ERAS Proposal violates the FPA's competition mandates. Clean Grid Alliance asserts that MISO has not addressed why 10 ERAS interconnection requests are reserved for independent power producers, while 50 ERAS interconnection requests are reserved for LSEs.[471] Clean Grid Alliance further contends that MISO has not addressed the potential for LSEs to unilaterally veto contracts with an independent power producer that apply for the 50 ERAS interconnection requests spots and instead prioritize their own generation resources for ERAS.[472] Clean Grid Alliance argues that the Revised ERAS Proposal lacks a requirement for RERRAs to openly consider proposals from independent power producers, allowing unilateral and unchecked applications by LSEs.

187. Michigan Commission argues that a "retail choice load" and "retail choice state" should be considered separate and distinct classifications for ERAS purposes. Michigan Commission notes that retail choice accounts for a very small portion of the state's electrical supply in the state of Michigan. Michigan Commission asserts that treating all

[467] Vistra Answer at 4- 5.

[468] *Id.* at 6.

[469] *Id.* (citing MISO Answer at 20; Witmeier Docket No. ER25-1674 Rebuttal Testimony at 7-8).

[470] *Id.* at 6-7.

[471] Clean Grid Alliance Second Answer at 1; *see also* Clean Grid Alliance Third Answer at 1-2.

[472] Clean Grid Alliance Second Answer at 2.

interconnection requests originating in Michigan as falling under the umbrella of a "retail choice state" is a clumsy simplification that would lead to unjust outcomes.[473]

188. Michigan Commission notes that in MISO's answer and the MISO Supplemental Answer, MISO uses the terms "retail choice states" and "retail choice load" interchangeably in a number of instances.[474] Michigan Commission compares this to MISO's statements in its transmittal, where MISO offered clear distinction between the terms.[475] Michigan Commission explains that Michigan statutory limitations prevent retail choice from exceeding 10% of an electric utility's average weather-adjusted retail sales.[476] Michigan Commission contends that classifying all interconnection requests from the state of Michigan as being located in a "retail choice state," as opposed to classifying each interconnection request based on whether it serves "retail choice load," would severely limit participation from interconnection requests located in Michigan.

189. Michigan Commission requests that the Commission clarify that interconnection requests serving "retail choice load" located in Michigan would be included in the eight-interconnection request retail choice carve out, but that the other 90% of the Michigan load will be eligible to participate in the 10-interconnection request independent power producer carve out or 50-interconnection request "non-retail choice" cap.[477]

190. Invenergy and Clean Grid Alliance raise concerns about certain information included in MISO's "Informational Guide" issued to stakeholders, which states in part that "[a]greements that are not legally binding, such as Letters of Intent, Memorandums of Understanding, or Term Sheets, will not be considered sufficient to meet the off-take agreement requirement."[478] Invenergy argues that this restriction violates the proposed

---

[473] Michigan Commission Answer at 3.

[474] *Id.* at 4-5 (citing MISO Supplemental Answer at 3; MISO Answer at 13).

[475] *Id.* at 5-6 (citing Transmittal at 8, 52-53).

[476] *Id.* at 6-7.

[477] *Id.* at 7.

[478] Invenergy Answer at 3-5 (citing MISO, *Expedited Resource Addition Study*, at 7 (posted July 11, 2025), https://cdn.misoenergy.org/ERAS%20Informational%20Guide707493.pdf ?v=20250711150053); Clean Grid Alliance Third Answer at 2-3 (citing same). Invenergy also attaches the ERAS Informational Guide as Exhibit A to its answer.

Tariff language and MISO's statements in this proceeding.[479] Both Invenergy and Clean Grid Alliance also argue that not allowing letters of intent and similar contracts to be included within the scope of "other agreements" under the proposed Tariff[480] raise a barrier to independent power producer participation in ERAS.[481]

(c) MISO Second Supplemental Answer

191. MISO states that any conflation of the terms "retail choice load" and "retail choice state" in its answers was inadvertent. MISO states that the Michigan Commission's understanding, that ERAS interconnection requests serving retail choice load located in Michigan would be included in the eight ERAS interconnection request carve out for retail choice, is correct. MISO further explains that interconnection requests intending to serve the remaining 90% of Michigan load can apply to the 10 ERAS interconnection request spots for independent power producers or the 50 ERAS interconnection request spots for non-retail choice loads.[482]

c. Commission Determination

192. MISO has proposed several eligibility requirements for the ERAS process. We accept these requirements and find them to be just and reasonable and not unduly discriminatory or preferential. Taken together, this comprehensive package of eligibility requirements will deter speculative interconnection requests from entering the ERAS process and minimize disruption to DPP interconnection requests.

193. At the outset, we review the Commission's consideration of open access matters in the context of Order Nos. 888 and 2003. In Order No. 888, the Commission first required open access requirements on a generic basis to address potential discrimination on the transmission system. By requiring an open access transmission tariff, the Commission applied–generically–a comparability standard to jurisdictional transmission providers as it had done previously on a case-by-case basis.[483] Under the comparability standard,

---

[479] *Id.* at 4-5.

[480] *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1(2)(d).

[481] Invenergy Answer at 4; Clean Grid Alliance Third Answer at 3.

[482] MISO Second Supplemental Answer at 2-3.

[483] The Commission therefore required "that all public utilities must offer . . . services on a non-discriminatory open access basis" and explained that "[a]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and

transmission service was to be offered to third parties on the same or comparable basis as that used by the transmission provider.[484] To implement its requirements, the Commission issued with Order No. 888 a *pro forma* open access transmission tariff and required public utilities to meet the new *pro forma* tariff non-price minimum terms and conditions.[485]

194. In Order No. 2003, the Commission applied Order No. 888's open access requirements to the generator interconnection process in recognition of the fact that generator interconnection is a "critical component of open access transmission service and thus is subject to the requirement that utilities offer comparable service under the [*pro forma* open access transmission tariff]."[486] The Commission found that it was appropriate to establish a standard set of generator interconnection procedures to "minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable."[487] To this end, the Commission adopted the *pro forma* LGIP and *pro forma* LGIA and amended its regulations to require all transmission providers to incorporate these standard procedures and agreement into their tariffs.[488]

195. More recently, the Commission rejected MISO's Initial ERAS Proposal because, first, it "place[d] no limit on the number of projects that could be entered in the ERAS process," and second, MISO did "not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating."[489] Here, we find that MISO's Revised ERAS Proposal sufficiently addresses these concerns identified in the May 2025 Order by capping the number and size of ERAS projects, strengthening the RERRA verification requirement, requiring ERAS interconnection requests to be located in the same Local Resource Zone as the resource adequacy or reliability need that it will address, absent reasonable

---

conditions, as the transmission provider's uses of the system." Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,647 (quoting *Am. Elec. Power Serv. Corp.*, 67 FERC ¶ 61,168, at 61,489 (1994)).

[484] *Id.*

[485] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at app. D, para. 13.6.

[486] Order No. 2003, 104 FERC ¶ 61,103 at PP 9, 12.

[487] *Id.* P 11.

[488] *See* 18 C.F.R. 35.28(f)(1) (2024).

[489] May 2024 Order at P 199-201.

exceptions, and making additional changes, as discussed further below. Collectively, these changes ensure the ERAS process is sufficiently limited in scope to swiftly address discrete, demonstrated resource adequacy needs in a narrowly tailored fashion, and on a temporary, time-limited basis. Additionally, we note that the limited, one-time design of the process weighed significantly on our decision here.

196. While interconnection requests that qualify for the ERAS process will have the ability to interconnect on a priority basis, ERAS does not present open access concerns because it is "open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others."[490] The Revised ERAS Proposal also applies identical eligibility criteria across all potential interconnection requests. This is similar to the PJM RRI construct, which allows for potential inclusion of any resource regardless of technology.[491] Furthermore, the Revised ERAS Proposal does not restrict or change interconnection customers' access to the DPP process.

197. We note that MISO's specific requirements for ERAS interconnection requests (e.g., location information for the load the ERAS interconnection request will serve, the limitation on the size of ERAS interconnection requests based on the identified resource adequacy shortfall, specific commercial readiness requirements, etc.), strengthened RERRA verification requirements, and MISO's commitment to publicly post detailed information about each ERAS interconnection request and its corresponding type of load served, establishes a clear and transparent process. Therefore, we disagree with protesters that MISO's Revised ERAS Proposal lacks objective and transparent criteria for participation in ERAS.

(a) RERRA Verification Requirement

198. We find that the proposed RERRA verification requirement is just and reasonable and not unduly discriminatory or preferential. We find that MISO has demonstrated that its proposal to require RERRAs to verify that either: (i) the new, incremental load addition is valid and not otherwise included in a resource plan or other process under the RERRA's purview, or (ii) that the generating facility will address a resource adequacy deficiency, is just and reasonable and not unduly discriminatory or preferential.[492]

199. We agree with MISO that the proposed RERRA verification requirement provides the necessary flexibility to recognize the different regulatory review processes across the

[490] Transmittal at 32.

[491] PJM RRI Order, 190 FERC ¶ 61,084 at PP 118, 121, 123.

[492] *See* Transmittal at 2.

states and RERRAs in the MISO region.[493] MISO has strengthened what was a "notification" requirement in its Initial ERAS Proposal to better ensure that RERRAs affirmatively verify interconnection requests will address specific resource adequacy needs that are not otherwise being addressed. We also find that it is reasonable and appropriate for MISO to allow RERRAs to determine which projects should be selected for ERAS, and to implement their own processes for making such determinations, as this approach strikes a reasonable balance between state authority over resource procurement and Commission authority over generation interconnecting to the interstate transmission system. Accordingly, we find that it is not necessary for MISO to establish scoring criteria or a ranking process for proposed ERAS projects, as protesters suggest. We note that here, we must evaluate whether MISO's Revised ERAS Proposal before us is just and reasonable, and we need not consider alternative proposals. Further, we agree with MISO that RERRAs are uniquely positioned to evaluate the needs in their regions and projects proposed by a developer or LSE[494] and that the Revised ERAS Proposal strikes a reasonable balance between ensuring that an ERAS interconnection request will serve a valid new load or meet a resource adequacy deficiency in MISO while respecting the state's jurisdiction over their own resource mix to address resource adequacy.[495] We disagree with EPSA, Invenergy, and other protesters[496] that state regulators, which are obliged to serve the public interest in accordance with state law, will not be objective in their RERRA verifications. We further find that MISO's reliance on RERRAs in the selection process for ERAS is a practical and expedient solution for each RERRA to identify ways to meet their specific resource adequacy challenges. We note that, as MISO explains, studying an interconnection request through the ERAS process does not pre-determine the outcome of an ERAS interconnection request, as any project must still obtain state approval through the state's corresponding regulatory review process.[497] As several commenters explain, the RERRA verification process balances MISO's need to verify projects that meet resource adequacy needs and the RERRAs' need to not prejudge generation certifications.[498]

---

[493] MISO Answer at 24-25.

[494] *Id.* at 22.

[495] *Id.* at 25-26; Southern Regulators Comments at 3.

[496] *Supra* at P 59, P 118.

[497] *See* Transmittal at 31.

[498] Louisiana and Mississippi Commissions Comments at 10; Otter Tail Comments at 4; Texas Commission Comments at 8.

200. We disagree with arguments that the RERRA verification requirement restricts open access by unduly discriminating against interconnection customers in retail choice jurisdictions, such as Illinois and Michigan. Rather, the Revised ERAS Proposal is available to interconnection customers regardless of whether they propose to operate in retail choice or non-retail choice jurisdictions. As MISO explains, the Revised ERAS Proposal was designed to be flexible to accommodate the various RERRA processes and regulatory constructs in the MISO region.[499] Further, the Revised ERAS Proposal adopts a carve out for eight interconnection requests serving retail choice loads (more than 10% of the total number of ERAS interconnection requests allowed under the program) to be studied in ERAS, which was added for the specific purpose of accommodating retail choice loads. Indeed, the Revised ERAS Proposal affords significant flexibility to accommodate interconnection customers in retail choice regions, including by permitting them to participate in ERAS without RERRA verification– a structural accommodation designed specifically to enable retail choice states and regions to participate fairly.[500] We also acknowledge that a significant majority of MISO's load is served through traditional vertically integrated processes.[501] Regarding Michigan Commission's request that MISO remove the proposed Tariff language in GIP section 3.9.1 that RERRA verification can be supported by "a state energy forecast, or other forward-looking forecast," we agree with MISO that the Tariff language is simply included as part of a list of potential information that RERRAs may use and that each RERRA will ultimately determine what information will be required for the ERAS project verification.[502]

---

[499] *See* MISO Answer at 25.

[500] Witmeier Testimony at 35-36. We note that Michigan Commission raises concerns with imprecise language in MISO's Answer and MISO's Supplemental Answer regarding retail choice loads and retail choice states; however, we find the proposed Tariff language, as revised by MISO's Supplemental Answer, is clear that the carve out for eight ERAS interconnection requests is for retail choice loads, which would include the 10% limit in Michigan, and the remaining ERAS interconnection requests slots are for non-retail choice load. Further, we note MISO's affirmation of this interpretation, and its explanation that interconnection requests serving the remaining 90% of load in Michigan can apply to ERAS under the 10 ERAS interconnection request spots for independent power producers or the 50 ERAS interconnection request spots for non-retail choice load. MISO Second Supplemental Answer at 2-3.

[501] Transmittal at 22 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 at P 67).

[502] MISO Answer at 24.

201. We find unpersuasive protester arguments that the RERRA verification is more difficult to satisfy for certain subcategories of interconnection requests. The record does not demonstrate that certain classes of interconnection customers will necessarily find it more difficult to receive a RERRA verification. RERRA verification may be triggered in numerous ways, not just through participation in one specific state-sponsored process. MISO's proposed GIP section 3.9.1.1 provides that the RERRA verifies that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed generating facility will address an identified resource adequacy deficiency; thus, MISO permits flexibility in satisfying this requirement.[503]

202. Further, we agree with MISO that the precedent in *Xcel* does not require rejection of the Revised ERAS Proposal. First, we note that *Xcel* involved the tariff of a non-independent transmission provider, and the Commission gives such transmission providers less flexibility than RTOs/ISOs to depart from the *pro forma* generator interconnection procedures and *pro forma* generator interconnection agreement.[504] Additionally, the proposal in *Xcel* required an interconnection customer taking part in a state-sponsored bidding process to drop out of the generator interconnection queue if the customer did not win the contract.[505] The *Xcel* proposal also appeared to allow projects submitted as part of the state process to jump ahead of other projects in the queue that were filed first.[506] In contrast, the Revised ERAS Proposal, though it provides an expedited process for certain interconnection requests, does not replace or interfere with the existing DPP process, which remains available to all interconnection requests.

(b) ERAS Cap and Carve Outs

203. We find that MISO's proposal to limit the total ERAS participation to 68 interconnection requests, with a carve out of eight interconnection requests to serve retail choice load and 10 interconnection requests for independent power producers, is just and reasonable and not unduly discriminatory or preferential. We agree with MISO that the Revised ERAS Proposal is narrowly tailored to meet MISO's near-term resource

---

[503] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.1(a)-(d).

[504] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 26 (allowing RTOs/ISOs to submit LGIP and LGIA terms and conditions that meet an "independent entity variation" standard, which is more flexible than the "consistent with or superior to" and "regional differences" standards). As discussed *supra* in part IV.B.2(c), the parameters of the RERRA verification requirement are clearly stated in MISO's Proposed Tariff.

[505] *Xcel*, 106 FERC ¶ 61,260 at P 22.

[506] *Id*.

adequacy and/or reliability needs.[507] We find that the Revised ERAS Proposal, including the proposed cap and carve outs, strikes a reasonable balance between ensuring broader participation and addressing the resource adequacy needs of the region, while providing reasonable limitations on the number of interconnection requests that will be studied through the ERAS process. Additionally, the proposed cap minimizes the potential for the types of delays that have occurred in the DPP queue to also manifest in the ERAS queue. MISO developed the 68 interconnection request cap in response to the May 2025 Order to limit ERAS participation to a manageable number of interconnection requests that MISO determined it can efficiently study in the short-term consistent with what the Commission approved for PJM's RRI process by design, with adjustments made to accommodate retail choice states and independent power producers in the MISO footprint.[508] Specifically, MISO explains that they coupled the cap with the two respective carve outs to ensure that independent power producers and entities in retail choice states have the exclusive opportunity to participate in ERAS. Therefore, we disagree with protesters' arguments that MISO's proposed cap and carve outs are arbitrary and unsupported.

204. We disagree with protesters' arguments that MISO's proposed cap and carve outs impede open access. Rather, as discussed above, we find that the proposed ERAS process is "open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others."[509] Additionally, we find that the carve outs for independent power producers and entities in retail choice states ensure that all interconnection customers will have comparable ability to seek to participate in the ERAS process, regardless of location and ownership type.[510] We also find that MISO's proposed cap is directly responsive to the Commission's concerns in the May 2025 Order that the Initial ERAS Proposal was not just and reasonable because it placed no limit on the number of projects that could be entered in the ERAS process.[511] Our acceptance of

[507] Transmittal at 35, 47.

[508] MISO Answer at 13.

[509] *See supra* P 190.

[510] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 123 (finding that PJM's proposal does not violate open access requirements because it provides all interconnection customers the comparable ability to submit an interconnection request for projects with at least 10 MW UCAP to be evaluated under PJM's proposed criteria). *See also* CAISO IPE Order, 188 FERC ¶ 61,225 at P 94 (finding that CAISO's proposal does not present open access issues because all interconnection customers are provided a "comparable ability" to join the cluster).

[511] May 2025 Order, 191 FERC ¶ 61,131 at P 199.

MISO's proposal, including the proposed cap of 68 interconnection requests, is consistent with that precedent.

205. We also disagree with protesters' contention that the Revised ERAS Proposal unduly discriminates against independent power producer interconnection requests with non-LSE agreements. In its answer, MISO provides clarification that the 10 ERAS interconnection request carve out for independent power producers with non-LSE agreements is not a cap on independent power producer interconnection requests, and independent power producers may *also* submit interconnection requests in the general group of 50 ERAS interconnection requests.[512] MISO explains that the purpose of the carve out is to address claims that LSEs could block independent power producers from participating in the ERAS process. We disagree with Clean Energy Associations' arguments that it is unclear whether independent power producers can compete on equitable terms for the general group of 50 spots in ERAS because MISO's proposed Tariff language is not clear on the types of agreements it will accept for those spots. MISO's proposed GIP section 3.9.1.2, which details the various types of acceptable executed agreements, applies to all ERAS interconnection customers regardless of whether they apply for the general 50 spots or the carve out spots for independent power producers and retail choice loads. Further, in its supplemental answer, MISO provides additional detail and sample Tariff provisions to clarify the carve out for independent power producers and states that it would welcome a directive to include such language in its Tariff on compliance.[513] We find that the Tariff provisions described by MISO in its supplemental answer will provide clarity to its Tariff. Therefore, we direct MISO to submit, within 30 days of the date of this order, revisions to its Tariff to incorporate the clarifying language included in its supplemental answer.

206. We further disagree with protesters' arguments that MISO should delay the implementation date, or otherwise provide more time, for independent power producer interconnection requests. Rather, we agree with MISO that creating separate start dates for different groups of ERAS interconnection requests may be impractical, administratively burdensome, and inappropriate.[514] Further, we find that MISO's proposed carve out to accommodate 10 independent power producer interconnection requests, in addition to MISO's clarification that independent power producer interconnection requests may also be included in the general group of 50 ERAS interconnection requests, ensures that independent power producers have comparable

[512] MISO Answer at 19.

[513] MISO Supplemental Answer at 4.

[514] MISO Answer at 20-21.

access to ERAS.[515] We therefore do not agree with protesters that additional processes for independent power producer interconnection requests are necessary to render the proposal just and reasonable.

(c) Other ERAS Eligibility Requirements

207. We find that the proposed ERAS executed agreement requirement is just and reasonable and not unduly discriminatory or preferential. Protesters argue that, to satisfy this requirement, the options for independent power producers necessarily require more effort than the self-supply option for LSEs.[516] We disagree that this potential distinction renders MISO's proposal unjust and unreasonable and find that MISO's proposal strikes a reasonable balance between reducing speculative projects and ensuring that certain types of interconnection requests or interconnection customers are not excluded from participating in ERAS. We find that the executed agreement requirement will help ensure that only truly "shovel ready" projects are proposed. As MISO states, this requirement ensures that some form of commercial arrangement exists pairing the ERAS project with the specified load and demonstrates that the ERAS project is not merely submitted in the hope of being selected to serve that need,[517] which would not support the objective of identifying more commercially ready projects in ERAS. We note that LSEs that meet the executed agreement requirement through a commitment to self-supply must still be verified by a RERRA, as is the case with the other types of executed agreements that independent power producers may use. We agree with MISO that this requirement prevents participation by speculative entities that "do not have buy in from the need driver."[518] Consequently, we agree that the proposed Tariff language indicates greater commercial readiness, thereby ensuring ERAS projects can meet MISO's urgent, near-term reliability and resource adequacy needs. While protesters may object to this requirement, MISO provides multiple options for interconnection customers to satisfy the executed agreement requirement.[519]

---

[515] *Id*. at 19 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 6-7); MISO Supplemental Answer at 4.

[516] *See, e.g.,* Clean Energy Associations Protest at 31; Clean Grid Alliance Protest at 26-27; EPSA Comments at 5; PIOs Protest at 5.

[517] Transmittal at 30-31.

[518] Witmeier Testimony at 42.

[519] MISO, Proposed Tariff, attach. X (GIP) (1750.0), § 3.9.1.2.

208. One such option is the eligibility of interconnection requests with "other agreements" to be included in the ERAS process.[520] By including such an option, MISO provides considerable flexibility for interconnection customers, including independent power producers and RERRAs seeking to procure supply from independent power producers, to satisfy this requirement.[521] We disagree with Clean Energy Associations that it is unclear which agreements apply to the 50 ERAS interconnection spots because the executed agreement requirements of proposed GIP section 3.9.1.2 apply to all ERAS interconnection requests. Further, as noted by both MISO and protesters, CAISO's IPE,[522] PJM's RRI,[523] and the 2024 MISO Queue Cap[524] proposals all incorporate aspects that encourage commercial readiness and, in each of those proceedings, the Commission found that those proposals were not in violation of open access requirements or otherwise unduly discriminatory. We find here that the Revised ERAS Proposal is largely consistent with these proposals, and likewise just and reasonable.

209. Finally, we find that the executed agreement requirement is tailored to achieve MISO's expressed objective for proposing ERAS, that is, meeting urgent, near-term resource adequacy or reliability needs by requiring interconnection customers to have

---

[520] *Id.* § 3.9.1.2(d). In response to stakeholder feedback that the executed agreement requirement may prove too onerous, MISO added this option to establish "a minimum requirement that an arrangement exists between the driver of the need and the project to address that need." Witmeier Testimony at 42.

[521] We disagree with Invenergy's and Clean Grid Alliance's arguments that agreements that are not legally binding should satisfy the "other agreement" requirement, as that would have the effect of rendering the "other agreement" requirement meaningless, thereby allowing projects that may not actually be needed to meet an identified resource adequacy need to be included in the ERAS process.

[522] CAISO IPE Order, 188 FERC ¶ 61,225 at P 174 ("[W]e find that CAISO's proposal to account for commercial interest in its evaluation of interconnection requests will help enable CAISO to prioritize the study of the most viable and needed interconnection requests under Cluster Study Criteria.").

[523] PJM RRI Order, 190 FERC ¶ 61,084 at P 155 ("We find PJM's proposed commercial operation date viability criteria . . . reasonably prioritize projects that have a reasonable likelihood of coming online in the near term to meet PJM's resource adequacy needs.").

[524] January 2025 Order, 190 FERC ¶ 61,057 at P 90 ("We also find that . . . [t]hese exempted interconnection requests [which count first towards the MW cap] are associated with generating facilities that are already in service or already have an executed GIA and, therefore, demonstrate a higher degree of commercial readiness.").

entered into agreements to serve specific load needs.[525] MISO has adequately demonstrated that this executed agreement eligibility criterion, along with the RERRA verification requirement, will help ensure that "shovel ready" projects that can meet RERRA-identified, near-term capacity needs are included in the ERAS process. Further, we find that MISO has provided consistent terms and conditions (and multiple avenues) for satisfying this requirement, and the record does not demonstrate that independent power producers, as a class, will be unable to satisfy this uniform requirement.

210. We find that MISO's proposed application fee, site control, milestone, commercial operation date, and Local Resource Zone requirements for ERAS interconnection requests are just and reasonable and not unduly discriminatory or preferential.[526] We agree with MISO that the proposed requirements will help prevent speculative projects from applying to the ERAS process, which will help ensure "shovel ready" projects that meet specific, near-term resource adequacy needs will be studied. While commenters argue that certain requirements, such as milestone payments, could be made more rigorous or stringent to better deter speculative projects from applying to the ERAS process, the Commission is not obligated to consider whether the ERAS proposal is more or less reasonable than other alternatives.[527] We note, however, that even if some protesters would prefer more stringency, the proposed ERAS application fee, site control, milestone, and commercial operation date requirements are all considerably stricter than those established for the DPP and thus designed to strictly limit participation in the ERAS process, which is both appropriate and consistent with MISO's objectives. Further, while other protesters argue that, for example, the $100,000 application fee and withdrawal penalties could be a barrier for them to enter ERAS,[528] we find that these requirements serve as meaningful deterrents against speculative projects.

211. Additionally, with ERAS, like PJM's RRI and CAISO's IPE proposals, MISO has tailored the requirements toward the goal of satisfying near-term reliability and resource adequacy needs by emphasizing "shovel readiness" and commercial readiness. Taken as a whole, MISO has proposed requiring ERAS interconnection customers to post greater financial and non-financial commercial readiness requirements and greater site control requirements, compared to DPP interconnection customers, as well as an NRIS requirement and RERRA verification and executed agreement requirements. We find

---

[525] PJM RRI Order, 190 FERC ¶ 61,084 at P 123; CAISO IPE Order, 188 FERC ¶ 61,225 at P 94.

[526] *Supra* PP 36, 38.

[527] *Supra* P 31.

[528] Clean Energy Associations Docket No. ER25-1674 Protest at 19; Clean Grid Alliance Protest at 79.

that, taken together, MISO has proposed a comprehensive package of eligibility requirements that will considerably deter speculative projects from applying to the ERAS process.

212. We disagree with protesters' arguments that MISO's proposed requirement that an ERAS interconnection request's level of requested interconnection service be no more than 150% of the identified MW need is unduly discriminatory. In the May 2025 Order, the Commission rejected MISO's Initial ERAS Proposal because it was not narrowly-tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs would be eligible for expedited study through the ERAS process.[529] We find that capping ERAS interconnection requests at 150% of the identified resource adequacy need is responsive to the May 2025 Order. MISO's proposal caps the ratio of interconnection service requested to needed generation in order to prevent gaming of the ERAS process, where the MW of a potential ERAS request could far exceed the identified MW need for new generation. Without such a cap, the ERAS request could be oversized and even a small MW need could be used for large new generating facilities to bypass the normal queue. MISO's proposal, as it states, is fuel-type agnostic, meaning there are no prohibitions on any specific fuel type from entering the ERAS process and that MISO does not take into account what type of generating facility is associated with an ERAS interconnection request. To the extent that an ERAS project would benefit economically from obtaining interconnection service over and above what is needed to address the RERRA-verified resource adequacy need, that project may seek additional interconnection service through the DPP process.[530] We acknowledge that there are practical limitations on what types of projects can compete for the ERAS process. However, we find that in this instance, where the ERAS process is limited to a small number of projects, and those projects are identified to meet a very specific need, MISO's proposal to ensure that there is a limitation to avoid any gaming concerns is a reasonable protection to put into place. As a result of this limitation, we disagree with protesters that the Local Resource Zone requirement is unduly discriminatory.[531] As noted above, MISO's addition of this requirement helps address the Commission' concern in the May 2025 Order that the ERAS proposal might not be tailored to addressing specific resource adequacy needs. Further, neither LSE nor independent power producer projects will be limited by this zonal requirement if they are included in an integrated resource plan. We find that MISO's Revised ERAS Proposal is therefore just and reasonable and not unduly discriminatory or preferential.

---

[529] May 2025 Order, 191 FERC ¶ 61,131 at P 202.

[530] Transmittal at 44; Witmeier Testimony at 68.

[531] *Supra* P 171.

4. ERAS Study Process

a. MISO's Filing

213. MISO proposes to study ERAS interconnection requests quarterly in a regional, serial "first-come, first-served" fashion using the existing engineering study process used in the DPP for ensuring full generator deliverability to load.[532] MISO explains that while both ERAS and DPP studies will use the same MTEP base case (i.e., the most current MTEP base case at the time of the DPP study cycle or the ERAS quarterly study process kickoff), they will include different generator assumptions. Specifically, MISO explains that, while the DPP will continue to include all prior-queued interconnection requests in base case models, the ERAS study will include only generating facilities with an executed GIA in such models.[533]

214. MISO states that the serial study is a key feature of ERAS and that it affords ERAS interconnection requests a better understanding of their impact on the transmission system when looking to address the needs of load. MISO also states that the traditional challenges related to reviewing interconnection requests on a serial basis are not present with ERAS because there will be a smaller number of interconnection requests to process, and they are expected to be geographically and electrically dispersed across the MISO footprint.[534] MISO states that if several ERAS interconnection requests are submitted in one geographical area at the same time, it will study the interconnection requests with the earliest submission time first, and the subsequent interconnection requests will be studied in the next available ERAS quarterly study period. However, MISO states that it does not anticipate this occurring very often due to the 10-interconnection request cap on ERAS interconnection requests per quarterly study period, its large footprint, and the strict eligibility requirements to enter the ERAS process.

215. Additionally, MISO proposes that existing DPP interconnection requests that have not reached Decision Point II in the DPP 2022, 2023, and later cycles will be eligible to transfer to ERAS.[535] MISO states that it is aware of several existing DPP interconnection requests that could apply to participate in ERAS. MISO explains that these DPP interconnection requests may remain in their DPP study group while applying for ERAS, and once admitted to ERAS, the interconnection requests must withdraw from the DPP

---

[532] Transmittal at 7-8; Witmeier Testimony at 52.

[533] Transmittal at 39; Witmeier Testimony at 52.

[534] Transmittal at 37-38.

[535] *Id.* at 37.

and will be subject to MISO's automatic withdrawal penalties and harm penalties. MISO asserts that the penalties are necessary because when interconnection requests drop out of the queue, the withdrawal causes harm to other interconnection requests in that study group. MISO explains that if a DPP interconnection request is deemed ineligible for ERAS, then it will forfeit the $100,000 D1 payment required with the ERAS application and will remain in its original DPP queue position.

216. MISO asserts that the Revised ERAS Proposal has been crafted to avoid supplanting the DPP or harming interconnection requests in the DPP interconnection queue.[536] MISO states that it plans to coordinate the ERAS, DPP, and expedited project review studies to maximize efficiency and reduce any impacts among these studies. MISO explains that network upgrades identified in ongoing MTEP studies that mitigate congestion in DPP and ERAS studies will remove the need for DPP and ERAS network upgrades once the MTEP project is approved. MISO contends that ERAS interconnection requests will not harm interconnection requests currently studied in the DPP process by taking existing transmission capacity headroom from active DPP interconnection requests. According to MISO, this is because the ERAS and DPP processes use the same MTEP base case as a starting point, and any headroom used by an ERAS interconnection request is not deducted from the DPP model, as ERAS interconnection requests will not be included in ongoing DPP studies.[537] MISO explains that the output of the DPP and ERAS models will be reconciled in the next MTEP, consistent with how MISO reconciles currently effective parallel processes through the next MTEP base case.[538]

217. MISO further explains that if transmission capacity is overallocated due to approved interconnection requests in both the ERAS and DPP processes, such

---

[536] *Id.* at 39.

[537] *Id.* at 42-43; Witmeier Testimony at 52. MISO explains that the DPP process uses the most up-to-date MTEP base case when the DPP study is kicked off and is not subsequently modified to include later-approved MTEP projects or ERAS interconnection requests after that kickoff. Witmeier Testimony at 53. For example, MISO explains that if it approves an ERAS interconnection request that will use the transmission capacity in MTEP 2024, and the DPP 2023 cycle is using MTEP 2023, the ERAS interconnection customer will not take away transmission capacity from any interconnection request in the DPP 2023 cycle. MISO also asserts that ERAS interconnection requests will not have early access to the newly available transmission headroom related to Long Range Transmission Plan Tranche 2.1 projects and will not disadvantage interconnection requests from the DPP 2025 cycle. Transmittal at 43.

[538] Transmittal at 43.

overallocation will be identified and mitigated in the next MTEP cycle.[539] In such a scenario, MISO explains that the transmission capacity overallocation would be discovered as part of the MTEP Deliverability Analysis, which ensures continued deliverability of generating facilities with NRIS.[540] MISO further contends that, even in an overallocation scenario, there will be no negative implications for either a DPP or ERAS interconnection request because both types of interconnection requests will be allowed to proceed, and neither will be required to pay additional costs due to the overallocation. MISO explains that the cost of the MTEP project needed to resolve overallocation will be allocated based on the existing Tariff rules, which will likely allocate the costs of the project to load within the transmission pricing zone where the transmission upgrade is located.[541] MISO explains that this will include the load that is benefiting from the ERAS and DPP interconnection requests, and this load will benefit from the network upgrades that were funded by the interconnection customers that went through those processes. Further, MISO asserts that the cost shift is consistent with existing processes. MISO explains that it has multiple planning processes, many performed in parallel with their own unique modeling assumptions and cost allocation methodologies.[542] MISO states that after projects are approved through their relevant processes, they are included in the base cases of subsequent studies based on the modeling assumptions for those studies. MISO states that it is not uncommon for new constraints to arise in subsequent studies driven by approved transmission and generation projects, as well as new load growth and generation retirement, and that, as new constraints are identified, new mitigation is identified, which could include another new transmission project necessary to ensure reliability.[543]

218. Finally, MISO asserts that the Revised ERAS Proposal meets the standard for an independent entity variation from the requirements of Order Nos. 2003 and 2023 because it fosters the increased development of economic generation by reducing interconnection

---

[539] *Id.*; Witmeier Testimony at 54.

[540] Witmeier Testimony at 54.

[541] *Id.* at 54-55.

[542] MISO references, for example, baseline reliability projects, market efficiency projects, multi-value projects, transmission deliverability service projects, interregional transmission projects, other projects, generator interconnection projects, and new generating facilities that are approved through the DPP, generator surplus, or generator replacement processes. *Id.* at 55-56.

[543] *Id.* at 56.

costs and time.[544] MISO asserts that because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined set of rules, rather than individual independent entity variations for the various differences between the cluster study process outlined in Order Nos. 2023 and 2023-A and the proposed serial-based study approach in ERAS.[545] MISO argues that using serial studies for ERAS accomplishes the purposes of Order Nos. 2003 and 2023 by minimizing the restudy risk that is inherent to multi-phase cluster studies so that ERAS generating facilities can be built quickly, without the risk of cascading restudies.[546] MISO contends that although the use of cluster studies is appropriate for the large queue volume seen in MISO's DPP process, the use of serial studies for ERAS will allow MISO to quickly study ERAS interconnection requests to address resource adequacy and/or reliability concerns and to meet the goals of the temporary ERAS process.

b. Responsive Pleadings

i. Comments in Support

219. Texas Commission argues that the Revised ERAS Proposal will not negatively impact DPP interconnection customers.[547] Texas Commission asserts that allowing interconnection customers in the DPP to transfer their interconnection request to ERAS before Decision Point II protects remaining DPP interconnection requests by preventing unplanned restudies that could result from late-stage transfers. Texas Commission adds that any interconnection requests that transfer from the DPP to ERAS must pay all applicable withdrawal penalties.

ii. Protests

(a) Serial Studies

220. Several protesters raise concerns with MISO's proposal to study ERAS interconnection requests serially. Clean Grid Alliance argues that ERAS represents a high-risk deviation that threatens to create ongoing disruptions to the DPP by destabilizing study models that interconnection customers rely on and causing cost shifts,

[544] Transmittal at 23-24 (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 11-12).

[545] Witmeier Testimony at 5, 67.

[546] Transmittal at 24.

[547] Texas Commission Comments at 11.

resulting in cascading restudies in ERAS and the DPP.[548] Relatedly, Clean Grid Alliance argues that despite MISO's proposal to adopt a cap of 10 ERAS interconnection requests per quarterly study period, the risk of cascading restudies is still present, as with any serial study approach.[549]

221. Invenergy argues that the Revised ERAS Proposal violates Order No. 2023's requirement that interconnection requests be studied in clusters.[550] Invenergy points to the Commission's language in the May 2025 Order that a serial interconnection study process may contribute to delays if multiple interconnection requests are submitted in the same quarter in the same area of the transmission system.[551] PIOs argue that in Order No. 2023, the Commission established the cluster study process as the cornerstone on which other reforms were oriented, and a separate serial study process would lead to unjust and unreasonable rates by diverting resources and causing delays to the existing DPP process, thereby undermining MISO's ability to identify the most efficient set of shared network upgrades for a DPP study group.[552] PIOs state that a serial study process also fails to realize the benefit of the efficient identification of shared network upgrades, and this will result in the under-identification of network upgrades assigned to ERAS interconnection requests, leading to reliance on the MTEP process to identify smaller, but more expensive, discrete technology solutions.[553] PIOs argue that ERAS is also not limited or transitional because its sunset date exceeds the full shift to cluster studies required by Order No. 2023 and may delay the realization of the benefits from Order No. 2023.[554]

222. PIOs argue that the serial study approach will detract staff resources from the DPP and that the Commission has previously denied requests to operate serial studies parallel to cluster studies.[555] PIOs contend that running serial studies for ERAS for multiple

---

[548] Clean Grid Alliance Protest at 5.

[549] *Id.* at 16-17.

[550] Invenergy Protest at 17 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178; Invenergy Docket No. ER25-1674 Protest at 3-6).

[551] *Id.* (citing Order No. 2023, 184 FERC ¶ 61,054 at P 178).

[552] PIOs Docket No. ER25-1674 Protest at 22-23.

[553] *Id.* at 28.

[554] *Id.* at 25.

[555] PIOs Protest at 20 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178).

years will delay MISO's processing of the DPP for those years.[556] PIOs further argue that MISO's serial study approach for ERAS will result in many network upgrade needs being identified for the first time in the MTEP process and that MISO's use of MTEP to build upgrades for ERAS interconnection requests does not achieve efficient transmission development.[557]

223. Invenergy argues that MISO has not justified the need for ERAS to span multiple study cycles rather than it occurring over one cycle.[558]

224. PIOs argue that MISO's proposed cap of 68 interconnection requests to be studied through the ERAS process does not address how the ERAS quarterly study period timeline will intersect with the DPP process.[559]

(b) Withdrawals

225. Clean Grid Alliance and Invenergy raise concerns about the effects of withdrawals from ERAS. Invenergy states that Order No. 2023 established withdrawal penalties to encourage interconnection customers to submit viable interconnection requests, discourage late-stage withdrawals, and reduce harm to other interconnections customers from withdrawals. Invenergy argues that ERAS does not accomplish the purposes of Order No. 2023 because the non-refundable D1 application fee and refundable M2 payment do not address the risk of restudies and delays nor the harms to other interconnection customers that would result from late-stage withdrawals from ERAS.[560] Clean Grid Alliance argues that interconnection customers in the DPP need an off-ramp without financial penalties when an ERAS interconnection request emerges and creates a negative financial impact.[561]

---

[556] *Id.* at 22.

[557] *Id.* at 18.

[558] Invenergy Protest at 14.

[559] PIOs Protest at 17.

[560] Invenergy Protest at 17-18.

[561] Clean Grid Alliance Protest at 23.

226. Clean Grid Alliance argues that if an ERAS interconnection request withdraws, restudies must occur in both ERAS and the DPP.[562] Clean Grid Alliance adds that such withdrawals would also impact the MTEP models because such models include ERAS interconnection requests after an EGIA is executed and a withdrawal after that point would render the MTEP models inaccurate. Further, Clean Grid Alliance asserts that such models are not designed to address interconnection requests.[563] PIOs add that they strongly oppose the creation of a "two-track" system in which ERAS interconnection requests are not fully studied until the MTEP.[564] Further, Clean Grid Alliance avers that if an ERAS EGIA is terminated, then the MTEP models that the DPP utilizes would no longer be accurate.[565]

227. Clean Grid Alliance argues that despite MISO's claims that withdrawals in ERAS will have little impact on DPP interconnection customers, any withdrawal will require restudies and administrative tasks. Clean Grid Alliance also notes that ERAS should consider the impacts to an ERAS interconnection request if the load it is intended to serve does not materialize.[566]

228. Invenergy asserts that MISO has not clarified how the withdrawal of an ERAS interconnection request from the ERAS queue may impact the DPP cluster study and DPP interconnection customers.[567] Invenergy argues that it is not just and reasonable to assign network upgrade costs to interconnection customers that are not the "but for"[568]

---

[562] *Id.* at 18. Clean Grid Alliance asserts that MISO's DPP 2023 models may include ERAS projects and that later DPP cycles would certainly include ERAS projects. *Id.*

[563] *Id.* at 17.

[564] PIOs Protest at 17-18.

[565] Clean Grid Alliance Protest at 18.

[566] *Id.* at 20.

[567] Invenergy Protest at 22.

[568] For generator interconnection-related network upgrades identified through the generator interconnection process, the Commission has accepted proposals by RTOs/ISOs to allocate the cost of such network upgrades solely to individual, or clusters of, interconnection customers. Through the generator interconnection process, the transmission provider studies individual or clusters of interconnection requests and identifies specific network upgrades needed to accommodate each interconnection request on an incremental basis (i.e., by determining whether a network upgrade is

cause of those costs, or that do not reflect their contribution to a needed network upgrade. Invenergy asserts that MISO should clarify its approach to ensure interconnection customers are paying for costs that they actually necessitate.

(c) Harm to Interconnection Customers

229. Several protesters argue that the Revised ERAS Proposal will harm DPP interconnection customers because it is a multi-year proposal.[569] They further argue that the Revised ERAS Proposal will delay the DPP because the serial studies in the ERAS process could detract from transmission providers' efforts to efficiently process cluster studies in the DPP and would not ensure reliable, efficient interconnection.[570] Several protesters assert that, unlike MISO's Revised ERAS Proposal, PJM's RRI and CAISO's IPE proposals were one-time, emergency proposals that were narrowly tailored to minimize harm and disruption to other interconnection customers.[571] Clean Grid Alliance further argues that MISO's proposed cap and carve outs are dissimilar from PJM's RRI because projects in PJM's RRI are processed under the same study cycle under PJM's standard interconnection queue, whereas MISO proposes to process ERAS interconnection requests in a separate queue.[572]

230. Several protesters argue that the Revised ERAS Proposal poses significant harm to DPP interconnection customers by diverting needed resources to conduct interconnection studies, such as limited staffing, and contend that implementing ERAS in parallel to the DPP will exacerbate these challenges, delay DPP processing, and increase network upgrade costs.[573] Invenergy asserts that MISO has failed to explain how the establishment

---

needed "but for" the interconnection of a generating facility). *See Sw. Power Pool, Inc.*, 122 FERC ¶ 61,060 (2008); *Sw. Power Pool, Inc.*, 171 FERC ¶ 61,272 (2020).

[569] Clean Grid Alliance Protest at 17, 51-53; Invenergy Protest at 20-21; NextEra Docket No. ER25-1674 Protest at 26-27.

[570] Clean Grid Alliance Protest at 16-19; Invenergy Protest at 20; NextEra Docket No. ER25-1674 Protest at 31 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178, 1347).

[571] MISO IPPs Docket No. ER25-1674 Protest at 7-8 (citing Kelliher Aff. at 5-6); NextEra Docket No. ER25-1674 Protest at 26-27; PIOs Docket No. ER25-1674 Protest at 42-43.

[572] Clean Grid Alliance Protest at 26, 67.

[573] Clean Energy Associations Docket No. ER25-1674 Protest at 31; Clean Grid Alliance Protest, attach. A (Declaration of Jennifer Ayers-Brasher) at 6 (Ayers-Brasher

of a second interconnection queue will not increase the interconnection delays already common in the existing queue.[574] Invenergy states that it applauds MISO for its commitment to hire additional staff to assist with the backlogged queue; however, this could be implemented independent of the ERAS proposal to address existing queue delays. Clean Grid Alliance further argues that MISO has not demonstrated how staffing challenges that have impacted DPP processing are not also present in facilitating ERAS.[575]

231. Clean Energy Associations assert that MISO's promise to prevent resources and staff time devoted to ERAS from being utilized to speed the DPP process is unfair to developers that have been waiting their turn to get through a backlogged queue.[576] Clean Energy Associations argue that, in spite of changes to the MISO proposal, such as the cap on ERAS participation and locational restrictions, ERAS still exists as a parallel process. Additionally, Clean Energy Associations argue that the task of studying ERAS interconnection requests while also studying DPP interconnection requests will further stretch MISO's already strained resources, risking delay to both the ERAS queue and the DPP queue.[577]

232. Clean Grid Alliance contends that a better approach to address large load additions is to allow large loads and interconnection customers to move through the existing processes in a coordinated fashion to create a net-zero impact on resource adequacy.[578]

233. Several protesters argue that the Revised ERAS Proposal allows for queue jumping.[579] PIOs argue that ERAS interconnection requests are effectively jumping the DPP queue, and much of the costs for ERAS interconnection customers to connect to the

---

Testimony); MISO IPPs Docket No. ER25-1674 Protest at 23-24; NextEra Docket No. ER25-1674 Protest 31-32; PIOs Docket No. ER25-1674 Protest at 15-16, 22, 26.

[574] Invenergy Protest at 20.

[575] Clean Grid Alliance Protest at 28.

[576] Clean Energy Associations Protest at 23.

[577] *Id.* (MISO, Transmittal Letter, Docket No. ER25-507-000, at 3 (Nov. 21, 2024); Witmeier Testimony at 13).

[578] Clean Grid Alliance Protest at 19.

[579] Clean Energy Associations Protest at 10; MISO IPPs Docket No. ER25-1674 Protest at 24; NextEra Docket No. ER25-1674 Protest at 3, 8, 10, 36, 41; PIOs Protest at 15, 20; PIOs Docket No. ER25-1674 Protest at 1-3, 8-9.

transmission system will be borne by DPP interconnection customers or unaffiliated load.[580] PIOs further argue that MISO's lack of a post hoc analysis to true up costs may result in ERAS interconnection customers paying less than their fair share.[581] PIOs assert that the advantages for projects that make it into ERAS, in addition to the lack of oversight from MISO, will create an incentive for RERRAs to approve as many in-state projects as possible.[582]

234. Clean Energy Associations assert that the Revised ERAS Proposal still allows for queue jumping from MISO's DPP to ERAS and interconnection requests, especially thermal resources proposed by LSEs, to offer additional capacity as surplus to be provided to an affiliate, effectively bypassing the DPP queue a second time.[583]

235. Additionally, Invenergy states that it has concerns that ERAS interconnection requests will have priority over DPP interconnection requests in the existing queue because ERAS interconnection requests will be studied first and can incorporate up-to-date information about available transmission capacity.[584] Invenergy also states that it has concerns about the unintended consequences of using two different base cases for ERAS and DPP interconnection requests that are being studied simultaneously.[585]

(d) Transmission Overallocation

236. Several protesters assert that MISO's Revised ERAS Proposal will allow ERAS interconnection customers to receive earlier access to transmission capacity. Protesters contend that ERAS interconnection requests will be studied faster than DPP interconnection requests, which will necessarily take up transmission capacity from the DPP, leading to increased costs for later queued DPP interconnection requests as ERAS interconnection requests queue jump the DPP.[586] MISO IPPs and NextEra assert that

---

[580] PIOs Protest at 15, 20.

[581] *Id.* at 15-16.

[582] *Id.* at 24-25.

[583] Clean Energy Associations Protest at 10.

[584] Invenergy Protest at 20-21.

[585] *Id.* at 21.

[586] Clean Grid Alliance Protest at 43-46; MISO IPPs Docket No. ER25-1674 Protest at 23-24; NextEra Docket No. ER25-1674 Protest at 42-43; 2025 Brattle Group Report at 26-27; PIOs Docket No. ER25-1674 Protest at 8-9,15-16.

once MISO incorporates ERAS interconnection requests with EGIAs into the MTEP model, which MISO has represented will occur for the DPP 2026 cycle, it will reduce the amount of transmission capacity available to DPP interconnection requests and subject those interconnection customers to higher network upgrade costs, potentially threatening the viability of their projects.[587] PIOs, NextEra, and Clean Grid Alliance similarly assert that the ERAS interconnection customers may pay less to interconnect through the ERAS process than if they had been studied as part of the DPP study group because ERAS interconnection requests: (1) will be double-counting the same headroom used by parallel DPP study groups; (2) will be advantaged in their use of existing headroom by excluding prior-queued interconnection requests from their interconnection study; and (3) will be arbitrarily less likely to trigger violations than DPP study groups because they will be evaluated serially and therefore gain disproportionately from existing headroom on the transmission system.[588]

237. MISO IPPs and NextEra further argue that faster study of ERAS interconnection requests may create contingent facilities that DPP interconnection requests are reliant upon, which may be delayed and subsequently harm reliant DPP interconnection requests.[589] Furthermore, Clean Grid Alliance argues that MISO's proposal to study ERAS interconnection requests and existing DPP study groups in parallel could ultimately lead to interconnection customers being subject to limited operations while MISO resolves capacity overallocation through the MTEP process.[590]

238. Several protesters raise concerns regarding reliability issues arising from interactions between ERAS projects and other interconnection customers, as the study model will exclude higher-queued interconnection customers without an interconnection agreement.[591] Clean Grid Alliance further argues that using the MTEP process to later address reliability concerns resulting from transmission capacity overallocation will not effectively address reliability concerns due to the limitations of NRIS and Energy

---

[587] MISO IPPs Docket No. ER25-1674 Protest at 24; NextEra Docket No. ER25-1674 Protest at 42-43.

[588] Clean Grid Alliance Protest at 43-46; 2025 Brattle Group Report at 26-27; PIOs Docket No. ER25-1674 Protest at 16.

[589] MISO IPPs Docket No. ER25-1674 Protest at 24-25; NextEra Docket No. ER25-1674 Protest at 43.

[590] Clean Grid Alliance Protest, Ayers-Brasher Testimony at 9.

[591] Clean Grid Alliance Protest at 20 (citing Clean Energy Associations Docket No. ER25-1674 Protest, Aff. of Warren Hess at ¶ 2, (filed Apr. 7, 2025)); NextEra Docket No. ER25-1674 Protest at 44.

Resource Interconnection Service studies.[592] Clean Grid Alliance argues that MISO's proposal to address transmission capacity overallocation through the next MTEP is unreasonable because there is no guarantee that the MTEP will produce the needed transmission, and it would shift ERAS-related costs to MTEP.[593]

239. Clean Energy Associations assert that, as with the Initial ERAS Proposal, the Revised ERAS Proposal fails to include late-stage DPP generating facilities in ERAS studies and will result in reduced network upgrades due to lower line loadings.[594] Clean Energy Associations aver that this will result in reliability gaps because MISO will not model all known near-term system changes that will occur when the ERAS generating facility reaches commercial operation. Clean Energy Associations assert that ERAS already departs from MISO's standard practice and that ERAS interconnection requests will be studied only with interconnection requests that have already achieved a GIA (i.e., interconnection requests from prior DPP cycles or completed ERAS cycles), while DPP interconnection requests will share headroom with all other interconnection requests in the DPP cycle.[595] Clean Energy Associations thus contend that ERAS will effectively push current reliability gaps onto future interconnection requests that are not in ERAS.[596]

240. Clean Energy Associations argue that the use of the annual MTEP reliability study process to resolve over-allocation of transmission headroom across ERAS and the DPP will not effectively address reliability concerns, as the annual MTEP reliability study process sets local balancing area constraints to limit power flows between local balancing areas, masking constraints that would otherwise show up in the DPP process.[597] Clean Energy Associations assert that, if MTEP does not capture the constraints caused by overallocated headroom due to not including all the expected projects coming online at the same time, the resulting unaddressed constraints will fall to subsequent DPP cycles.

241. Furthermore, Clean Energy Associations argue that, even with a numerical cap on the total number of interconnection requests and the number of interconnection requests per zone, ERAS interconnection requests could still trigger significant reliability impacts

---

[592] Clean Grid Alliance Protest at 20 (citing Clean Energy Associations Protest, Docket No. ER25-1674, Aff. at P 2).

[593] *Id.* at 22.

[594] Clean Energy Associations Protest at 12, 21.

[595] *Id.* at 12-13.

[596] *Id.* at 13.

[597] *Id.* at 22.

that require substantial network upgrades, if they are large and located in areas where they have a high impact on a highly congested part of the transmission system.[598] Clean Energy Associations assert that the cap on the number of interconnection requests and interconnection requests per zone quarterly does not negate the potential for overlapping allocation of headroom that is insufficiently reconciled via MTEP.

242. Relatedly, NextEra argues that the MTEP process may not be able to resolve issues caused by ERAS because: (1) timing issues between ERAS and MTEP processes may limit the efficacy of the MTEP to prevent costs of network upgrades needed to resolve issues missed in the ERAS process from being passed on to interconnection customers in the DPP; (2) the MTEP and DPP processes use different underlying assumptions, including dispatch assumptions; and (3) MISO assesses deliverability differently in the MTEP and DPP processes.[599]

243. Furthermore, several protesters raise concerns regarding cost allocation for network upgrades that are identified in the MTEP process. MISO IPPs argue that the ERAS study process will not identify the need for required upgrades, possibly leaving customers that entered DPP prior to the ERAS interconnection requests left to foot the bill.[600] Furthermore, MISO IPPs assert that allocating costs for network upgrades triggered by ERAS interconnection requests through MTEP could run afoul of the Commission's cost allocation requirements and be inconsistent with cost causation requirements.[601]

244. Some protesters assert that the Revised ERAS Proposal will violate cost causation principles by allocating costs of such upgrades to load.[602] NextEra states that MISO claims that costs will be allocated to load in the same transmission pricing zone where a network upgrade is located and expects that "this load will include the load that is

---

[598] *Id.* at 24.

[599] NextEra Docket No. ER25-1674 Protest at 45 (citing Cody Doll Aff. at 7-9).

[600] Clean Energy Associations Docket No. ER25-1674 Protest at 28-29; MISO IPPs Docket No. ER25-1674 Protest at 23; NextEra Docket No. ER25-1674 Protest at 45-48; PIOs Docket No. ER25-1674 Protest at 19-21.

[601] MISO IPPs ERAS 1.0 Protest at 47.

[602] Clean Energy Associations Docket No. ER25-1674 Protest at 28-29; NextEra Docket No. ER25-1674 Protest at 46-48.

benefiting from the ERAS and DPP interconnection requests;[603] however, NextEra argues that interconnection requests frequently trigger the need for network upgrades in neighboring transmission zones, meaning that transmission customers and ratepayers in one transmission pricing zone may be required to subsidize the costs of serving other transmission customers and ratepayers.[604] NextEra argues that this subsidization may be exacerbated because the claimed need leading to issuance of a RERRA verification for an ERAS interconnection request may be limited to a locality or municipality, but that ERAS interconnection request may eventually create a need for significant upgrades through the MTEP process, requiring a transmission pricing zone to subsidize the cost of upgrades to meet a locality's need.[605] PIOs contend that while there are circumstances in which it is appropriate for load to pay the costs of new transmission rather than generation, that is not the case for the proposed cost shifts driven by ERAS.[606] PIOs argue that the proposed shift in costs driven by ERAS projects to load would be haphazard and would not necessarily ensure that the portion of load that shoulders any such costs is also the portion of load that benefits from the ERAS and DPP generating facilities whose full impact was not captured in their parallel studies.[607] Thus, PIOs argue that the ERAS proposal moves transmission planning in the opposite direction from the Commission's policies established in Order Nos. 1000[608] and 1920.[609]

---

[603] NextEra Docket No. ER25-1674 Protest at 47 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 38:5-9).

[604] *Id*. at 47-48.

[605] *Id.* at 48.

[606] PIOs Docket No. ER25-1674 Protest at 21.

[607] *Id.* (citing PIOs Docket No. ER25-1674 Protest, attach. A (Testimony of Houtan Moaveni) at 14-16).

[608] *Id.*; *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[609] PIOs Docket No. ER25-1674 Protest at 21; *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, *order on reh'g & clarification*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), Order No. 1920-B, 191 FERC ¶ 61,026 (2025), *appeal docketed sub nom. Appalachian Voices v. FERC*, No. 24-1650 (4th Cir. pet. consolidated Aug. 8, 2024).

245. Clean Grid Alliance argues that MISO's proposal to allow "backfilling" of a quarterly study period is unjust and unreasonable.[610]

iii. Answers

(a) MISO Answer

246. MISO asserts that the Revised ERAS Proposal will not take resources away from DPP processing because it will use the ERAS application fee and study deposit to cover costs related to processing ERAS interconnection requests, including improving study tools and hiring additional staff.[611] MISO further asserts that it has carefully crafted the Revised ERAS Proposal to avoid supplanting the DPP or harming DPP interconnection customers.[612]

247. MISO contends that, as the Commission noted in the PJM RRI Order, arguments that separate study processes like ERAS will harm existing interconnection customers are speculative. MISO asserts that it is not proposing to delay the DPP queue processing schedule as a result of the ERAS proposal, that no DPP milestones have been altered, and that no interconnection customer will lose its queue position.[613] MISO also argues that it has taken steps to ensure that current DPP interconnection requests are protected from losing available transmission capacity.[614] MISO states that it will build the ERAS model based on the existing MTEP model, which will not remove any available transmission system headroom from DPP interconnection requests.[615] MISO explains that ERAS will only incorporate approved generating facilities, while the DPP will incorporate all higher and equally-queued interconnection requests, which includes speculative projects.[616] MISO explains that it will follow its existing processes to determine if already planned projects can alleviate constraints. MISO also argues that by not updating the base case for each DPP cycle once the study process starts, except for changes due to withdrawals

---

[610] Clean Grid Alliance Protest at 28.

[611] MISO Docket No. ER25-1674 Answer at 47.

[612] MISO Answer at 29.

[613] MISO Docket No. ER25-1674 Answer at 17 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 245).

[614] MISO Answer at 29-30; MISO Docket No. ER25-1674 Answer at 39.

[615] MISO Docket No. ER25-1674 Answer at 39-40.

[616] MISO Answer at 2.

or generator retirements, transmission capacity available for DPP interconnection requests is not being taken away by ERAS interconnection requests approved outside the DPP cycle.[617] MISO also argues that using the latest, approved MTEP base case to reconcile the models insulates existing DPP interconnection requests from costs shifts due to the ERAS process. MISO argues that there is no evidentiary support to protesters' arguments that ERAS interconnection requests will result in higher network upgrade costs for DPP interconnection requests and that ERAS requires interconnection customers to pay all network upgrade costs associated with their proposed interconnection requests.[618] MISO further states that network upgrades approved through the ERAS process can be used to mitigate constraints in the DPP process, which will have a positive impact on the DPP.

248. Regarding concerns about whether the ERAS proposal will protect DPP interconnection customers from ERAS interconnection customer withdrawals prior to EGIA execution, MISO asserts that DPP interconnection requests are adequately protected from ERAS withdrawals because an ERAS interconnection request that does not reach EGIA execution will never be modeled in DPP cycles and therefore cannot impact the DPP.[619] Further, MISO asserts that the proposed ERAS study process will ensure that a withdrawal will not cause restudies in the ERAS process, as ERAS interconnection requests will be studied serially, or in the DPP process, as the parallel ERAS and DPP studies are done in tandem. MISO clarifies that a DPP interconnection request that moves to ERAS will be liable for any harm caused to other DPP interconnection requests in the study group and will be subject to automatic withdrawal penalties.

249. In response to concerns about ERAS not being a one-time process, MISO states that it does not want to limit participation to a one-time opportunity if some interconnection customers or RERRAs take more time to identify projects that could participate in ERAS.[620] MISO contends that it would need to do a cluster study for a one-time process, which would prevent interconnection customers from more timely knowing their full network upgrade costs, as those costs would be contingent on the decisions made by all the other ERAS interconnection requests in the cluster.

---

[617] *Id.* at 29-30; MISO Docket No. ER25-1674 Answer at 40 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 35).

[618] MISO Docket No. ER25-1674 Answer at 40.

[619] MISO Docket No. ER25-1674 Supplemental Answer at 5.

[620] MISO Docket No. ER25-1674 Answer at 35-36.

250. MISO also argues that the ERAS proposal will not result in queue jumping because the ERAS process is open to all interconnection customers that meet the eligibility criteria, and any interconnection request selected to participate is not similarly situated to other interconnection requests because that request has a greater ability to meet near-term resource adequacy needs.[621] MISO contends that, similar to the Commission's findings when accepting PJM's RRI proposal, no DPP interconnection requests will be displaced by ERAS, no DPP milestones have been altered, and no DPP interconnection customer will lose its queue position as a result of ERAS.[622]

251. MISO states that, because the Revised ERAS Proposal establishes a cap on the number of interconnection request that will be studied under ERAS and will occur over a limited timeframe, the DPP is further protected.[623] MISO asserts that addressing the ongoing delays in the DPP to reach a study processing time of one year remains a priority for MISO, and ERAS is a separate process needed to address near-term reliability and resource adequacy needs.

(b) Additional Answers

252. Clean Grid Alliance argues that MISO's contention that its staffing resources will not be diverted from processing the DPP queue to support the ERAS process is unsupported.[624] Clean Grid Alliance also disagrees with MISO's arguments that the ERAS proposal would not enable queue jumping and states that the Commission has previously rejected such queue jumping proposals.[625]

253. Clean Grid Alliance argues that MISO has not addressed protesters' arguments that ERAS will harm DPP interconnection customers through disrupting modeling, causing cascading restudies, and shifting costs.[626] In addition, Clean Grid Alliance disagrees with MISO's arguments that the ERAS process will not take headroom from

---

[621] *Id.* at 34.

[622] *Id.* (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 245).

[623] MISO Answer at 30.

[624] Clean Grid Alliance Docket No. ER25-1674 Answer at 24-25.

[625] *Id.* at 16 (citing MISO Docket No. ER25-1674 Answer at 34; *Sw. Power Pool, Inc*., 147 FERC ¶ 61,201 at P 124).

[626] Clean Grid Alliance First Answer at 8-9.

DPP interconnection requests.[627] Clean Grid Alliance argues that MISO has not explained how the implementation of ERAS will not result in the same transmission capacity being allocated twice in concurrent DPP (i.e., DPP 2023 cycle) and ERAS studies, and then not result in interconnection requests in the next DPP cycle (i.e., DPP 2025 cycle) having to address any overallocations as pre-existing conditions. Clean Grid Alliance argues that if ERAS interconnection customers are interconnecting to, or depend on, the same transmission lines as DPP interconnection customers, then, given ERAS interconnection customers' priority to that transmission headroom, the DPP interconnection customers will be harmed.[628] Clean Grid Alliance argues that such a scenario is likely because MISO will not model DPP interconnection requests, even late-stage DPP Phase III interconnection requests, in ERAS interconnection studies.[629] In addition, Clean Grid Alliance claims that the ERAS process may harm DPP interconnection requests because serial restudies will absorb MISO staff time, given that restudies are necessary when an interconnection request withdraws, regardless of network upgrades remaining, due to the potential for counterflows.[630] In addition, Clean Grid Alliance raises concerns that MISO's proposal does not require ERAS interconnection customers to provide 100% of network upgrade costs as an initial payment, arguing that MISO may have to initiate legal action to collect funds from an ERAS interconnection customer with an EGIA that withdraws absent such protection.[631]

254. Clean Energy Associations argue that MISO fails to refute arguments that the ERAS study process will harm DPP interconnection customers stemming from: (1) uncertainty regarding the dispatch model that would be used for ERAS studies; (2) MISO's proposal to not include late-stage DPP interconnection requests in ERAS studies; and (3) use of the annual MTEP process to resolve over-allocation of transmission headroom across ERAS and DPP processes.[632] Clean Energy Associations argue that MISO's proposal will systematically advantage ERAS interconnection

---

[627] *Id.* at 17.

[628] Clean Grid Alliance Docket No. ER25-1674 Answer at 18.

[629] Clean Grid Alliance First Answer at 8 (citing Clean Grid Alliance Protest at 21); Clean Grid Alliance Docket No. ER25-1674 Answer at 18. Clean Grid Alliance argues that MISO's submissions in prior filings before the Commission have noted that interconnection requests in DPP Phase III have a 90% success rate. *Id.*

[630] Clean Grid Alliance Docket No. ER25-1674 Answer at 19.

[631] *Id.* at 26.

[632] Clean Grid Alliance First Answer at 8 (citing Clean Grid Alliance Protest at 21); Clean Grid Alliance Docket No. ER25-1674 Answer at 10.

requests and lead to unresolved constraints, which will fall to subsequent DPP interconnection requests to address if the MTEP does not capture them. Clean Grid Alliance further asserts that LSEs have not committed to paying the cost for additional transmission capacity that MISO proposes to shift to MTEP.[633]

255. Clean Grid Alliance argues that MISO's admission, that ERAS interconnection requests "could be included in the ERAS process but ultimately not be approved in the state regulatory process and thus may not be completed at that point in time," conflicts with MISO's assertions that restudies in the ERAS process will not be an issue.[634]

256. MISO IPPs state that MISO did not respond to MISO IPPs' arguments that different study assumptions for ERAS and DPP interconnection requests will cause MISO to underestimate network upgrades for ERAS interconnection requests and shift the costs of those network upgrades to other entities.[635]

257. Clean Grid Alliance argues that MISO fails to address the Revised ERAS Proposal's harm to the DPP by allowing queue jumping and introducing reliability gaps caused by transmission capacity overallocation. Clean Grid Alliance avers that the Revised ERAS Proposal will only mitigate reliability impacts within the local balancing area where an ERAS interconnection request is located, while the DPP mitigates reliability impacts across the entire MISO footprint. Clean Grid Alliance contends that the Revised ERAS Proposal's approach is discriminatory. Clean Grid Alliance asserts that these harms are unnecessary because MISO already has the provisional GIA process through which interconnection customers can pursue an expedited interconnection and GIA.[636]

258. PIOs argue that MISO's answer does not address PIOs' concern that ERAS interconnection requests will receive more favorable study assumptions, which will likely enable ERAS interconnection requests to pay less for interconnection service than similarly situated DPP interconnection requests. PIOs contend that MISO's reliance on the fact that ERAS will incorporate only approved generating facilities, while the DPP includes all prior queued interconnection requests, is a key characteristic that is creating

---

[633] Clean Grid Alliance First Answer at 9 (citing Clean Grid Alliance Protest at 22).

[634] Clean Grid Alliance Docket No. ER25-1674 Answer at 13-14 (citing MISO Docket No. ER25-1674 Answer at 16).

[635] MISO IPPs Answer at 13.

[636] Clean Grid Alliance Second Answer at 3.

the undue preference for ERAS interconnection requests.[637] PIOs aver that a process that subjects interconnection requests to two different baseline study assumptions will not eliminate inherent risks present when multiple interconnection requests rely on the same transmission infrastructure.[638]

c. Commission Determination

259. We find that MISO's proposal to evaluate ERAS interconnection requests in a separate, serial study process is just and reasonable and not unduly discriminatory or preferential and accomplishes the purposes of Order Nos. 2003 and 2023. Further, we find that MISO's Revised ERAS Proposal will not harm DPP interconnection customers and that the cap on the number of ERAS interconnection requests that may be studied provides a further guardrail to ensure ERAS is a limited process.

260. MISO seeks variations from the *pro forma* LGIP and *pro forma* LGIA under the independent entity variation standard, which provides that the proposed variations must be just, reasonable, not unduly discriminatory or preferential, and accomplish the purposes of Order Nos. 2003 and 2023.[639] MISO proposes to study ERAS interconnection requests using its existing NRIS modeling standards and the most recent MTEP base case that includes all generating facilities with executed GIAs. While protesters argue that limiting ERAS to 10 serial studies per quarterly study period does not alleviate the concern that the proposed serial study process is inconsistent with the requirements of Order No. 2023, we find that MISO's proposed approach is just and reasonable and accomplishes the purposes of Order Nos. 2003 and 2023. MISO's proposal to use a serial study process here does not present concerns related to queue withdrawals and restudies traditionally raised by serial cluster processes[640] because, as discussed above, interconnection projects in the ERAS process are less likely to be speculative and withdraw due to the enhanced commercial readiness requirements. MISO represents that there will not be any DPP or ERAS restudies associated with any ERAS projects that do withdraw.[641] Further, withdrawing ERAS interconnection customers are also responsible for any network upgrade costs assigned to them in an EGIA, which would mitigate risks regarding any potential cost impacts to lower-queued

---

[637] PIOs Answer at 8-9.

[638] *Id.* at 9.

[639] *See* Transmittal at 23.

[640] Order No. 2023, 184 FERC ¶ 61,054 at P 47.

[641] MISO Docket No. ER25-1674 Supplemental Answer at 5.

interconnection customers.[642] Moreover, MISO's proposal to study ERAS interconnection requests using its existing NRIS modeling standards and the most recent MTEP base case while including all generating facilities with executed GIAs is just and reasonable because it will allow MISO to expedite the ERAS studies through a serial process that excludes DPP interconnection requests that are more likely to withdraw, e.g., those DPP interconnection requests that have not executed GIAs, because including such resources would create uncertainty in the ERAS study process.

261. We find protesters' claims that the implementation of ERAS will delay MISO's processing of the DPP to be speculative. As MISO explains, it will use the ERAS non-refundable application fee to support the necessary staffing and resources to allow MISO to process both the DPP and ERAS studies without negative impacts to the DPP queue.[643] We also note MISO's stated commitment to ensure proper staffing and resource allocation to avoid any delays to DPP study processing.[644]

262. Further, protesters argue that interconnection customers in future DPP cycles may be subject to higher network upgrade costs or curtailments under a potential scenario where the MTEP process does not identify network upgrades sufficient to resolve issues created by parallel DPP and ERAS studies. We find protesters' argument that MTEP might not address needed reliability upgrades to be speculative, and so we disagree with protesters that the potential for such an outcome renders MISO's proposal unjust and unreasonable. The Commission has previously found that interconnection customers have no legal rights to a given system topology or to whether upgrades may be required.[645] Further, given the way MISO's interconnection queue has been designed to encourage orderly withdrawals, lower-queued interconnection customers are frequently faced with changing network upgrade costs. Moreover, MISO explains that its proposed ERAS study will identify network upgrades and other facilities necessary for the interconnection of ERAS interconnection customers, and we therefore disagree that ERAS projects will

---

[642] MISO, Proposed Tariff, attach. X (GIP) (171.0.0), § 3.9.6.3.

[643] MISO Answer at 141; MISO Docket No. ER25-1674 Answer at 47.

[644] MISO Docket No. ER25-1674 Answer at 47. Specifically, MISO states that the non-refundable $100,000 D1 application fee will allow MISO "to hire additional staff, as needed, to ensure that adoption of the ERAS process does not create harmful effects to the DPP interconnection process" and that it "is committed to making other resource or staffing changes to ensure that this remains true throughout the ERAS process." *Id.*

[645] PJM RRI Order, 190 FERC ¶ 61,084 at P 192.

either be inappropriately assigned network upgrade costs or not assigned network upgrade costs at all.

263. We do not find persuasive protesters' arguments that interconnection customers currently in the DPP queue will be harmed as a result of ERAS and will be subject to higher network upgrade costs due to the ERAS proposal. As MISO explains, DPP studies use the most recent MTEP model at the time that MISO commences the DPP study cycle as the base case, and that model will not be updated to include ERAS interconnection requests. Furthermore, as Texas Commission explains, the Revised ERAS Proposal protects interconnection customers currently in the DPP queue by preventing late-stage transfers, which could lead to unplanned restudies, and by requiring interconnection requests that transfer to ERAS to pay withdrawal penalties.[646] Therefore, interconnection customers currently in the DPP process will not see higher assigned network upgrade costs because their interconnection requests will continue to be studied without accounting for ERAS interconnection requests. In addition, we note that interconnection customers that submit interconnection requests into future DPP cycles will have notice of the existence of the ERAS process prior to submitting their interconnection requests and could factor the ERAS process into their commercial decisions. Furthermore, we note that DPP interconnection requests that have not reached Decision Point II in the 2022, 2023, and later cycles are eligible to transfer to the ERAS process, if they meet the eligibility requirements.[647]

264. In response to protesters' arguments that MISO's proposal will result in cost allocation inconsistent with cost causation, and that there is the potential for needed network upgrades to be identified in the MTEP process because ERAS interconnection requests may not be assigned their full "but for" costs, we find MISO's proposal to address through its existing processes any deliverability issues identified as a result of differences between the models used in the ERAS and DPP studies to be just and reasonable. As MISO explains, its current Tariff allocates to load the costs of network upgrades identified through its MTEP process, as needed, to maintain resource deliverability. Therefore, MISO's proposal is consistent with its existing, Commission-approved process for addressing deliverability issues identified outside of its process for studying interconnection requests.[648]

265. Protesters contend that the ERAS process is not a "one time" process because it includes multiple, quarterly study periods over several years. We do not find this concern

---

[646] Texas Commission Comments at 11.

[647] Transmittal at 22.

[648] MISO Answer at Tab B, MISO Transmittal, Docket No. ER25-1674, at 30 (filed Apr. 21, 2025); Witmeier Docket No. ER25-1674 Rebuttal Testimony at 38-39.

persuasive. The Revised ERAS Proposal is timebound and will sunset at the earlier of August 31, 2027 or when MISO has studied 68 ERAS interconnection requests. We disagree with the arguments that the Revised ERAS Proposal must be a one-time cluster study, such as PJM's RRI proposal, to be just and reasonable. The Commission's acceptance of PJM's RRI does not preclude the Commission from accepting a different RTO or ISO proposal, such as MISO's proposal, which is not only tailored to address the specific needs of the MISO region but also considers the distinct characteristics of the MISO region.[649]

5. Affected Systems

a. MISO's Filing

266. MISO explains that, regarding affected system studies, neighboring transmission providers will have the right to evaluate the impact of ERAS interconnection requests on their transmission systems, just as with DPP interconnection requests.[650] MISO further explains that any ERAS interconnection request that meets the Joint Targeted Interconnection Queue (JTIQ) criteria will be subject to JTIQ study procedures.[651] MISO notes that the Revised ERAS Proposal was designed with the expectation that MISO would use existing affected system study processes and that it is actively working with multiple seams partners to develop additional seams procedures to incorporate the ERAS process.[652]

267. MISO proposes that ERAS interconnection requests will adhere to the same affected system screening criteria as applicable to DPP interconnection requests, with the following exceptions:

a. The transmission provider will submit all necessary information for an affected system to study an ERAS interconnection request no later than 10 calendar days prior to the applicable ERAS study kickoff;

---

[649] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 826 (stating that RTOs/ISOs "shall have greater flexibility to customize [their] interconnection procedures and agreement to fit regional needs").

[650] Transmittal at 38.

[651] *Id.* at 38, 48, 51, 55, 59-60; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 1, 3.9.5, 7.3.1.4, 7.3.2.3.1.

[652] Witmeier Testimony at 64.

b. The transmission provider will provide any affected system analysis received from the affected system to the ERAS interconnection customer promptly upon receipt;

c. If affected system study results and cost information are not available at the time an EGIA is tendered, then such EGIA will include an obligation to execute any agreements for the study, construction, or funding of network upgrades identified by the affected system within 15 calendar days after such an agreement is tendered to the interconnection customer;

d. The transmission provider will submit ERAS interconnection request information to the affected system operator individually and request that the affected system operator study the ERAS interconnection request serially; and

e. When MISO and the affected system operator use a specified point in the DPP, such as a decision point or a DPP phase kickoff date, to establish the queue priority date of a MISO interconnection request, MISO will assert a queue priority date for ERAS interconnection requests as of the date that MISO commences the ERAS system impact study unless the controlling agreement between MISO and the affected system operator provides for an alternative queue priority date. Additionally, for interconnection requests with an earlier queue priority date, "in accordance with this section 9.4.3 (a) will have a higher relative queue priority than those with a later queue priority date."[653]

268. MISO states that it will provide affected system study results in the final ERAS study report, in the draft EGIA, or when they are received from the affected system operator, if they are not available at the time of the final ERAS study results and/or at the time of EGIA execution.[654] MISO explains that, in the event that an interconnection customer withdraws its ERAS interconnection request and terminates its EGIA after execution of the EGIA or after requesting that the EGIA be filed unexecuted, the interconnection customer will be liable for the network upgrades arising from the affected system study process.[655]

---

[653] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.5.2.

[654] Transmittal at 38; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 3.9.3, 3.9.5; *see also* Witmeier Testimony at 65.

[655] Witmeier Testimony at 66.

269. MISO contends that this process will ensure a timely affected system study appropriate for the ERAS process while still providing necessary flexibility for MISO and individual seams partners.[656]

b. Responsive Pleadings

i. Protests

270. MISO IPPs argue that the Revised ERAS Proposal fails to adequately address how MISO will manage affected system studies for ERAS interconnection requests and how such affected system studies may impact DPP interconnection requests.[657] MISO IPPs argue that affected system studies are time-consuming and can cause substantial delays, yet MISO largely ignores the issue of affected system studies, merely stating that MISO will include affected system study results in the ERAS study if available, and if not available, MISO will provide them separately when received from the applicable affected system. MISO IPPs argue that this leaves questions, including whether affected system studies will cause delays in processing ERAS interconnection requests and/or DPP interconnection requests.[658]

271. Invenergy argues that ERAS does not align with Order No. 2023's requirement that affected system studies be completed in clusters in order of queue priority based on when the affected system study agreement was executed. Invenergy states that while MISO has filed provisions for its JTIQ with SPP, it does not explain how the serial nature of ERAS would interface with the affected system cluster study process.[659]

272. Clean Grid Alliance argues that information regarding the affected system process remains unclear and lacks critical details on MISO's coordination with its seams partners.[660] Clean Grid Alliance asserts that MISO has not explained how neighboring transmission systems would be able to individually process 10 ERAS interconnection requests quarterly through 2027, as well as how those studies would align with the affected system operator's study of DPP interconnection requests and its own queue.

---

[656] Transmittal at 51.

[657] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[658] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[659] Invenergy Protest at 18.

[660] Clean Grid Alliance Protest at 27.

Similarly, MISO IPPs argue that it is unclear whether affected system studies will cause delays in processing DPP interconnection requests.[661] Clean Grid Alliance argues that affected system coordination has been a significant source of queue processing delays, and such delays are misaligned with meeting MISO's claimed near-term resource adequacy and reliability needs.[662]

273. Clean Energy Associations contend that ERAS interconnection customers may be put in the position to sign an EGIA before receiving information about affected system networks upgrades and argues that this conflicts with the requirement adopted in Order No. 2023 for a host transmission provider to delay the deadline for an interconnection customer to file its LGIA, at an interconnection customer's request, if the affected system study results have not been received.[663]

274. Clean Energy Associations argue that the risk of limited information on affected system study results might deter independent power producers' interconnection requests that are well suited to meet near-term resource adequacy needs from applying for the ERAS process, while posing relatively little risk to LSE-owned or affiliated generation that can pass along unexpected affected system network upgrade costs to consumers.[664]

ii. Answers

(a) MISO Answer

275. In response to concerns regarding the lack of detail on the affected system study process for ERAS interconnection requests, MISO explains that ERAS interconnection requests will be subject to the same affected system process as DPP interconnection requests, including the same criteria used by MISO's seams partners.[665]

276. Further, in response to protesters' arguments that LSEs can pass along affected system costs to consumers without bearing the same risk as independent power producers, MISO states that differences in risk profiles already existed between LSEs and

---

[661] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[662] Clean Grid Alliance Protest at 28.

[663] Clean Energy Associations Docket No. ER25-1674 Protest at 24-25.

[664] Clean Energy Associations Protest at 24-25 (citing Clean Energy Associations Docket No. ER25-1674 Protest at 25, 48-51).

[665] MISO Docket No. ER25-1674 Answer at 41.

independent power producers prior to the Revised ERAS Proposal and are not a result of that proposal.[666]

(b) Additional Answers

277. Clean Grid Alliance argues that MISO fails to explain how the Revised ERAS Proposal would lead to an expedited process to bring new generation online if ERAS and DPP interconnection requests are subject to the same affected system processes.[667] Clean Grid Alliance also argues that MISO does not provide sufficient information about how it will coordinate affected system studies with all seams partners and that the lack of information does not satisfy MISO's burden under FPA section 205.[668] Further, Clean Grid Alliance argues that MISO's statement that it will merely request that an affected system operator study ERAS interconnection requests on a serial basis is contrary to the Commission's reforms in Order No. 2023 to firm-up the affected system study process and draw clearly defined parameters.[669]

c. Commission Determination

278. We find that MISO's proposed process to notify affected system operators of potential impacts to their transmission systems from ERAS interconnection requests in a serial fashion, as well as MISO's requirements regarding affected system network upgrade obligations on ERAS interconnection customers, to be just and reasonable and not unduly discriminatory or preferential and accomplishes the purposes of Order Nos. 2003 and 2023. MISO's proposal will ensure that ERAS interconnection requests are evaluated for impacts on affected systems like other interconnection requests, consistent with Commission precedent.[670] As MISO states, the ERAS interconnection requests are subject to the same affected system study process as DPP interconnection requests, including the same criteria currently used by MISO's seams partners, albeit MISO will notify those seams partners of potential impacts in a serial manner. MISO's proposal to use a serial study process here does not present concerns related to queue

---

[666] *Id.* at 29-30.

[667] Clean Grid Alliance Docket No. ER25-1674 Answer at 10.

[668] *Id.* at 20-21.

[669] *Id.* at 22 (citing MISO Answer at 44; Order No. 2023, 184 FERC ¶ 61,054 at P 1111).

[670] Order No. 2003, 104 FERC ¶ 61,103 at P 118.

withdrawals and restudies traditionally raised by serial study processes[671] because, as discussed above, interconnection projects in the ERAS process are less likely to be speculative and withdraw due to the enhanced commercial readiness requirements.

279. We disagree with protesters that requiring ERAS interconnection customers to execute an EGIA, or request that it be filed unexecuted, prior to receiving affected system study results is unjust and unreasonable. The proposed ERAS eligibility criteria and requirements are intended to ensure that non-speculative, "shovel ready" projects enter the ERAS process and move expeditiously to EGIA execution. To the extent that an interconnection customer is not willing to execute an EGIA without affected system study results, the interconnection customer may withdraw from the ERAS process.[672] Additionally, as the Commission noted in Order No. 2023-A, there is no requirement for affected system network upgrade costs to be known at the time of LGIA execution, which in ERAS would be at the time of EGIA execution or requesting that it be filed unexecuted.[673]

280. Finally, we disagree with the concerns raised by certain protesters that MISO's Revised ERAS Proposal provides vague information regarding affected system studies. We find that MISO's proposed Tariff language provides sufficient detail regarding the process in which MISO will notify affected system operators of potential impacts from ERAS interconnection requests, as well as how MISO will relay the results of affected system analysis to ERAS interconnection customers.

6. Miscellaneous

a. MISO's Filing

281. MISO states that following the Commission's rejection of the Initial ERAS Proposal, it re-engaged with stakeholders to develop the Revised ERAS Proposal.[674] MISO states that it presented the Revised ERAS Proposal at the Planning Action Committee meeting on May 28, 2025 and received feedback from stakeholders through

[671] Order No. 2023, 184 FERC ¶ 61,054 at P 47.

[672] We note that withdrawing ERAS interconnection requests that withdraw prior to executing an EGIA will forfeit their non-refundable $100,000 D1 payment. *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0) § 3.9.2.

[673] Order No. 2023-A, 186 FERC ¶ 61,199 at P 494.

[674] Transmittal at 19.

its informal feedback tool.[675] MISO also asserts that it held "dozens" of calls with stakeholders.[676]

a. Responsive Pleadings

i. Comments in Support

282. Big Rivers Electric asserts that the Revised ERAS Proposal underwent extensive review and discussion through MISO's stakeholder process, and MISO adopted many stakeholder recommendations to enhance the proposal's effectiveness. Big Rivers Electric further states that MISO has provided extensive opportunity for all interested parties to participate in stakeholder processes and that the Revised ERAS Proposal reflects substantial stakeholder input gathered over the past several months.[677]

283. CenterPoint states that MISO's Revised ERAS Proposal enjoys widespread support from the State of Indiana, as expressed by a concurrent resolution passed by the Indiana House of Representatives and Senate urging reform processes to expedite the approval of electric transmission and generation projects and a letter from Indiana Governor Mike Braun expressing his strong support for MISO's efforts to address pressing resource adequacy challenges.[678] Furthermore, CenterPoint notes that Indiana Energy Association has expressed its support for the Revised ERAS Proposal, as it will help account for the growing complexity of the energy landscape and ensure that sufficient resources are available to meet immediate and future demand.

---

[675] *Id.* (citing MISO, *Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20St udy%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf.; Informal Feedback (2025), MISO, https://www.misoenergy.org/engage/stakeholder-feedback/2025/informalfeedback-2025/).

[676] Witmeier Testimony at 23.

[677] Big Rivers Electric Comments at 5-6.

[678] CenterPoint Comments at 5-6.

ii. Protests

284. Several protesters raise concerns over the stakeholder process that preceded the Revised ERAS Proposal.[679] Clean Grid Alliance states that MISO never informed stakeholders of its plan to request a shortened comment period.[680] PIOs contend that the silence from some states likely reflects the inadequate time to respond under the shortened comment period rather than their support.[681] Illinois Commission and PIOs assert that pre-filing stakeholder engagement on the Revised ERAS Proposal was limited due to MISO's quick refiling of its ERAS proposal, and there was no formal stakeholder feedback requested by MISO prior to filing the revisions.[682] PIOs and Clean Grid Alliance assert that MISO did not publicly share its proposed Tariff language prior to filing with the Commission.[683] PIOs state that they have had conversations with Minnesota State Commissioners who have expressed concern over the Revised ERAS Proposal.[684]

285. PIOs argue that this lack of stakeholder engagement renders the Revised ERAS Proposal legally vulnerable. According to PIOs, the record is insufficient for the Commission to make a reasoned decision, and MISO violated Order No. 719,[685] by which an RTO/ISO must be responsive to the needs of its customers and stakeholders.[686] PIOs allege that because MISO bypassed its normal stakeholder process and rushed the revision of the ERAS proposal, MISO failed to "make well-informed decisions that

---

[679] Clean Grid Alliance Protest at 3-4; Illinois Commission Comments at 3; PIOs Protest at 1, 32-37.

[680] Clean Grid Alliance Protest at 3-4.

[681] PIOs Protest at 40.

[682] *Id.* at 34; Illinois Commission Comments at 3.

[683] Clean Grid Alliance Protest at 3; PIOs Protest at 35.

[684] PIOs Protest at 40-41 (citing Minnesota Commission, *MISO Quarterly Update Meeting* (June 6, 2025)). PIOs include quotes from Minnesota State Commissioners Hwikwon Ham and Joseph Sullivan, who voiced concerns over MISO's Revised ERAS Proposal process at the Minnesota Commission meeting on June 6, 2025.

[685] *Wholesale Competition in Regions with Organized Elec. Mkts*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[686] PIOs Protest at 37-38.

reflect the full range of competing interests that may be affected," and also failed to meet the ongoing responsiveness requirements of Order No. 719.[687] PIOs contend that MISO has also arguably failed to meet the remaining criteria outlined in Order No. 719 to ensure a balancing of diverse interests and representation of minority interests because the Revised ERAS Proposal has not gone before the MISO Board of Directors.[688]

286. Finally, PIOs assert that MISO's rushed process to submit the Revised ERAS Proposal has resulted in numerous errors in its filing. PIOs state that, for example, the proposed Tariff language includes references in the EGIA to the three-year grace period provided for under GIP section 4.4.4 but that this conflicts with the language in proposed GIP section 3.9.8, which states that no changes to the commercial operation date are permitted once an interconnection request enters ERAS.[689]

iii. Answers

(a) MISO Answer

287. MISO states that it worked to quickly file the Revised ERAS Proposal to address the failures identified by the Commission in the May 2025 Order and to create a fully workable process that could be implemented this year.[690] MISO disagrees with protesters that the stakeholder process was rushed.[691] MISO asserts that it made targeted changes to its Initial ERAS Proposal, which was crafted with extensive stakeholder input, and that the changes were not created in a vacuum. MISO asserts that the Revised ERAS Proposal applied lessons learned from the original stakeholder process, considered the Commission's findings, and engaged with stakeholders on an individual basis to receive feedback on the proposed changes. Thus, MISO states that the Revised ERAS Proposal is the result of MISO responding to input from a variety of parties, stakeholder protests to the Initial ERAS Proposal, and feedback from individual stakeholders on the Revised ERAS Proposal. MISO asserts that it was necessary to quickly file the Revised ERAS

---

[687] *Id.* at 37 (citing Order No. 719, 125 FERC ¶ 61,071 at PP 506-509).

[688] *Id*.

[689] *Id.* at 38 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 4.4.4, 3.9.8; *id.* app. 6 (GIA) (106.0.0), art. 2.3.1.

[690] MISO Answer at 11.

[691] *Id.* (citing Clean Energy Associations Protest at 5-6; COMPP Protest at 6-7; Illinois Commission Comments at 2-3; Michigan Commission Protest at 2; PIOs Protest at 3).

Proposal to enable MISO to begin ERAS this year and to address its short-term resource adequacy and reliability needs.[692]

288. MISO states that it acknowledges the diverse interests of the stakeholder community but argues that developing a proposal that satisfies every interest of each stakeholder is not possible, nor should that be the benchmark.[693]

(b) Additional Answers

289. PIOs contend that MISO has not explained how holding a full stakeholder process to implement their suggestions would hinder the intended benefits of the Revised ERAS Proposal.[694] PIOs point out that OMS has not provided input on the Revised ERAS Proposal and that the Commission should not assume parties that supported the Initial ERAS Proposal also support the instant filing. PIOs argue that MISO's statements that it reached out to certain stakeholders are indicative of a secretive and exclusive process that falls short of the standards for stakeholder engagement outlined in Order No. 719. PIOs further argue that it is concerning that many of the revisions following the May 2025 Order appear to be at the request of individual stakeholders.[695]

b. Commission Determination

290. We disagree with protesters' contention that MISO's stakeholder process for the Revised ERAS Proposal is a basis to reject the filing. We find that MISO's stakeholder process for the Revised ERAS Proposal, though it entailed a more targeted approach than the one taken for the Initial ERAS Proposal, was sufficiently responsive to stakeholder feedback within the context of the revisions that MISO sought to make in its Revised ERAS Proposal, and consistent with MISO's existing governance procedures and stakeholder processes that the Commission has already approved as compliant with Order No. 719.[696] MISO states that the Revised ERAS Proposal focused on limited modifications to the Initial ERAS Proposal in order to be responsive to the May 2025 Order, and as such, MISO engaged with stakeholders on a targeted basis to refine an

---

[692] *Id.* at 11-12.

[693] *Id.* at 30.

[694] PIOs Answer at 13 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 5).

[695] *Id.*

[696] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,068, at P 44 (2010).

existing prior proposal, as compared to the more extensive stakeholder process for the Initial ERAS Proposal, which included discussions, presentations, and numerous opportunities for stakeholder input.[697] According to MISO, following the May 2025 Order, MISO re-engaged with its stakeholders at the May 28, 2025 Planning Action Committee meeting, and thereafter, MISO received feedback from stakeholders through its informal feedback tool.[698] In addition, MISO states that the Revised ERAS Proposal incorporates feedback that was received for the Initial ERAS Proposal.[699] Thus, MISO asserts that the Revised ERAS Proposal responds to the Commission's guidance, stakeholder protests to the Initial ERAS Proposal, input from a variety of parties, and feedback from individual stakeholders on the Revised ERAS Proposal.[700]

The Commission orders:

(A) MISO's proposed Tariff revisions are hereby accepted, subject to condition, effective August 6, 2025, as requested, as discussed in the body of this order.

(B) MISO is hereby directed to submit a further compliance filing within 30 days of the date of this order, as discussed in the body of this order.

By the Commission. Commissioner Chang is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Secretary.

[697] *See* Transmittal at 18.

[698] *Id.* at 19.

[699] Witmeier Docket No. ER25-1674 Rebuttal Testimony at 5.

[700] MISO Answer at 11.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. Docket No. ER25-2454-000

(Issued July 21, 2025)

CHANG, Commissioner, *concurring*:

1. I concur in today's order accepting Midcontinent Independent System Operator, Inc's (MISO) Expedited Resource Addition Study (ERAS) proposal as just and reasonable, and not unduly discriminatory or preferential, because it is sufficiently tailored to reflect the specific needs that are rapidly arising in the MISO region. I write separately, given my prior dissent on PJM Interconnection, L.L.C.'s (PJM) Reliability Resource Initiative (RRI) proposal.[1]

2. Regulators and the utilities we oversee are responsible for ensuring that customers' needs are reliably and affordably met. For more than two decades, the Commission and the industry have relied on non-discriminatory interconnection procedures to facilitate access for new generation of all types. It is no secret that queues around the country, and particularly in the regional transmission organizations, are strained, which has significantly delayed the interconnection of new resources needed to serve new and existing loads. In response, the Commission, grid operators, and utilities are searching for solutions to process backlogged queues and expedite the interconnection of new resources.[2]

3. As a general matter, when faced with the challenge of the existing queue backlogs, I disfavor temporary solutions that do not help resolve the underlying problem. One-off short-term fixes can create additional problems and at times beget further one-off fixes. Developing these types of temporary proposals can detract from our collective efforts to address the more fundamental underlying issues. Furthermore, interconnection queue proposals that grant priority access to the system are, at minimum, in tension with

[1] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025) (Chang, Comm'r, dissenting).

[2] *See, e.g.*, *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024); *Midcontinent Indep. Sys. Operator, Inc.*, 190 FERC ¶ 61,057 (2025) (approving MISO's generator interconnection queue cap).

competition and open access to the transmission system, which I believe have served customers well and should not be lightly discarded. Any deviations from the traditional Commission policy or existing, generally applicable queue procedures have a very high bar to clear.

4. Nonetheless, to meet the challenge of resource adequacy, as I explained in my dissent on PJM's RRI proposal, I am open to considering region-specific deviations from generally applicable interconnection queue procedures, given the Commission's paramount obligation to ensure that system operators can reliably serve their loads. Consistent with my analysis there, I assess here (1) whether MISO has demonstrated a sufficient reliability need to justify its proposed deviation, and (2) whether its proposed solution to that need is sufficiently tailored to address it. As discussed below, I find that MISO has satisfied both showings and I therefore approve its filing.

5. In the MISO region, most of the states and load serving entities (LSEs) have full responsibility over their own resource adequacy. These entities must ensure that sufficient supply and demand-side resources will be able to meet the growing load, and they do so through resource planning processes that state regulators oversee. Those resource planning processes are used to determine the utilities' investments in and contracts with new resources. MISO's proposal, which gives states a voice in which projects are selected for ERAS, codifies that selection decision into MISO's tariff for a limited set of projects that can most readily meet the specific needs identified by the states. MISO's ERAS process essentially moves the timing of when a proposed resource is selected by a state or an LSE from the after the interconnection process to before it, while maintaining the responsibility of the states and LSEs to ensure their footprints are resource adequate.

6. To facilitate such role for the state and the LSEs, each ERAS interconnection request must be accompanied by a written verification from a state entity that there is a need for the resource to interconnect to the MISO system. Along with that verification, the resource must have a power purchase agreement or other agreement to ensure that the resource has a commercial off-taker that plans to use the generation as soon as it is in commercial operation. The state and the LSE must identify a specific load addition or resource adequacy need that the planned resource will meet. These factors ensure that the ERAS projects are needed, supported by state entities, and sufficiently commercially viable to ensure the projects are actually constructed.

7. MISO has put in place significant requirements for the interconnection customers seeking to use the ERAS process. First, the proposal allows for an addition of only 68 projects to an expedited interconnection process. Of those 68, eight are reserved for restructured states, ten are reserved for independent power producers, and the remaining 50 are available to any type of interconnection customer, whether they are affiliated with the interconnecting transmission owner or not. While limiting the number of projects that

can participate is a minimum requirement to avoid creating a perpetual process under which certain resources can bypass the existing queue, it is not only the limited number of projects that makes MISO's ERAS proposal acceptable. Next, each project must demonstrate full site control and must provide several financial payments to enter the process. Both of these requirements will limit the projects that seek to enter the ERAS queue and will limit withdrawals from the ERAS process and other queue disruptions.

8. MISO's proposal requires that it study all of the ERAS requests by the earlier of the completion of all 68 studies or August 31, 2027. This ensures that this process does not linger past the time where MISO explains it needs the new generation the most and ensures that the ERAS process is truly a one-time exception to the traditional interconnection process as required by Orders No. 2003 and 2023. It is extremely important that this process is limited to a short term, one-time fix, and I appreciate MISO's revised requirements to ensure it completes the ERAS process by August 31, 2027.

9. MISO also explains that it will study no more than 10 projects per quarter, which will necessarily limit the staffing needed to process the ERAS studies. While MISO is implementing various computational solutions to improve the processing of interconnection requests, it is still constrained by the number of personnel that can work on the studies. By limiting to studying only 10 projects per quarter, MISO's ERAS proposal should help ensure that MISO's staff has enough bandwidth to continue the important work on processing the existing interconnection queue.[3]

10. Overall, I am persuaded that MISO's ERAS proposal is a just and reasonable solution to, in the short term, add resources that can address imminent demand growth and locational resource adequacy challenges. I truly hope this process is a successful bridge to the more durable and equitable implementation of MISO's latest interconnection reforms and the reforms required by Order No. 2023, which should provide better long-term outcomes under the Commission's traditional open access framework.

For these reasons, I respectfully concur.

_____

Judy W. Chang
Commissioner

[3] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064, at P 110 (2025).

Document Content(s)

ER25-2454-000.docx.....1

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 92
Energy Emergency EO

Federal Register
Vol. 90, No. 18
Wednesday, January 29, 2025

Presidential Documents

Title 3—

The President

Executive Order 14156 of January 20, 2025

Declaring a National Energy Emergency

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the National Emergencies Act (50 U.S.C. 1601 *et seq.*) (''NEA''), and section 301 of title 3, United States Code, it is hereby ordered:

Section 1. *Purpose.* The energy and critical minerals (''energy'') identification, leasing, development, production, transportation, refining, and generation capacity of the United States are all far too inadequate to meet our Nation's needs. We need a reliable, diversified, and affordable supply of energy to drive our Nation's manufacturing, transportation, agriculture, and defense industries, and to sustain the basics of modern life and military preparedness. Caused by the harmful and shortsighted policies of the previous administration, our Nation's inadequate energy supply and infrastructure causes and makes worse the high energy prices that devastate Americans, particularly those living on low- and fixed-incomes.

This active threat to the American people from high energy prices is exacerbated by our Nation's diminished capacity to insulate itself from hostile foreign actors. Energy security is an increasingly crucial theater of global competition. In an effort to harm the American people, hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets. An affordable and reliable domestic supply of energy is a fundamental requirement for the national and economic security of any nation.

The integrity and expansion of our Nation's energy infrastructure—from coast to coast—is an immediate and pressing priority for the protection of the United States' national and economic security. It is imperative that the Federal government puts the physical and economic wellbeing of the American people first.

Moreover, the United States has the potential to use its unrealized energy resources domestically, and to sell to international allies and partners a reliable, diversified, and affordable supply of energy. This would create jobs and economic prosperity for Americans forgotten in the present economy, improve the United States' trade balance, help our country compete with hostile foreign powers, strengthen relations with allies and partners, and support international peace and security. Accordingly, our Nation's dangerous energy situation inflicts unnecessary and perilous constraints on our foreign policy.

The policies of the previous administration have driven our Nation into a national emergency, where a precariously inadequate and intermittent energy supply, and an increasingly unreliable grid, require swift and decisive action. Without immediate remedy, this situation will dramatically deteriorate in the near future due to a high demand for energy and natural resources to power the next generation of technology. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid. Our Nation's current inadequate development of domestic energy resources leaves us vulnerable to hostile foreign actors and poses an imminent and growing threat to the United States' prosperity and national security.

These numerous problems are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population. The United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy. In light of these findings, I hereby declare a national emergency.

Sec. 2. *Emergency Approvals.* (a) The heads of executive departments and agencies (''agencies'') shall identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands. If an agency assesses that use of either Federal eminent domain authorities or authorities afforded under the Defense Production Act (Public Law 81–774, 50 U.S.C. 4501 *et seq.*) are necessary to achieve this objective, the agency shall submit recommendations for a course of action to the President, through the Assistant to the President for National Security Affairs.

(b) Consistent with 42 U.S.C. 7545(c)(4)(C)(ii)(III), the Administrator of the Environmental Protection Agency, after consultation with, and concurrence by, the Secretary of Energy, shall consider issuing emergency fuel waivers to allow the year-round sale of E15 gasoline to meet any projected temporary shortfalls in the supply of gasoline across the Nation.

Sec. 3. *Expediting the Delivery of Energy Infrastructure.* (a) To facilitate the Nation's energy supply, agencies shall identify and use all relevant lawful emergency and other authorities available to them to expedite the completion of all authorized and appropriated infrastructure, energy, environmental, and natural resources projects that are within the identified authority of each of the Secretaries to perform or to advance.

(b) To protect the collective national and economic security of the United States, agencies shall identify and use all lawful emergency or other authorities available to them to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States, Northeast of the United States, and Alaska.

(c) The Secretaries shall provide such reports regarding activities under this section as may be requested by the Assistant to the President for Economic Policy.

Sec. 4. *Emergency Regulations and Nationwide Permits Under the Clean Water Act (CWA) and Other Statutes Administered by the Army Corps of Engineers.* (a) Within 30 days from the date of this order, the heads of all agencies, as well as the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to emergency treatment pursuant to the regulations and nationwide permits promulgated by the Corps, or jointly by the Corps and EPA, pursuant to section 404 of the Clean Water Act, 33 U.S.C. 1344, section 10 of the Rivers and Harbors Act of March 3, 1899, 33 U.S.C. 403, and section 103 of the Marine Protection Research and Sanctuaries Act of 1972, 33 U.S.C. 1413 (collectively, the ''emergency Army Corps permitting provisions''); and

(ii) shall provide a summary report, listing such actions, to the Director of the Office of Management and Budget (''OMB''); the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Assistant to the President for Economic Policy; and the Chairman of the Council on Environmental Quality (CEQ). Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the fullest extent possible and consistent with applicable law, the emergency Army Corps permitting provisions to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, each department and agency shall provide a status report to the OMB Director; the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Director of the National Economic Council; and the Chairman of the CEQ. Each such report shall list actions taken within subsection (a)(i) of this section, shall list the status of any previously reported planned or potential actions, and shall list any new planned or potential actions that fall within subsection (a)(i). Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order.

(d) The Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, shall be available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the emergency Army Corps permitting provisions. The Administrator of the EPA shall provide prompt cooperation to the Secretary of the Army and to agencies in connection with the discharge of the responsibilities described in this section.

Sec. 5. *Endangered Species Act (ESA) Emergency Consultation Regulations.* (a) No later than 30 days from the date of this order, the heads of all agencies tasked in this order shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to the regulation on consultations in emergencies, 50 CFR 402.05, promulgated by the Secretary of the Interior and the Secretary of Commerce pursuant to the Endangered Species Act (''ESA''), 16 U.S.C. 1531 *et seq.;* and

(ii) provide a summary report, listing such actions, to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the maximum extent permissible under applicable law, the ESA regulation on consultations in emergencies, to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, the head of each agency shall provide a status report to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Each such report shall list actions taken within the categories described in subsection (a)(i) of this section, the status of any previously reported planned or potential actions, and any new planned or potential actions within these categories. Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order. The OMB Director may grant discretionary exemptions from this reporting requirement.

(d) The Secretary of the Interior shall ensure that the Director of the Fish and Wildlife Service, or the Director's authorized representative, is available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the ESA's emergency regulations. The Secretary of Commerce shall ensure that the Assistant Administrator for Fisheries for the National Marine Fisheries Service, or the Assistant Administrator's authorized representative, is available for such consultation and to take such other action.

Sec. 6. *Convening the Endangered Species Act Committee.* (a) In acting as Chairman of the Endangered Species Act Committee, the Secretary of the Interior shall convene the Endangered Species Act Committee not less than quarterly, unless otherwise required by law, to review and consider any lawful applications submitted by an agency, the Governor of a State,

or any applicant for a permit or license who submits for exemption from obligations imposed by Section 7 of the ESA.

(b) To the extent practicable under the law, the Secretary of the Interior shall ensure a prompt and efficient review of all submissions described in subsection (a) of this section, to include identification of any legal deficiencies, in order to ensure an initial determination within 20 days of receipt and the ability to convene the Endangered Species Act Committee to resolve the submission within 140 days of such initial determination of eligibility.

(c) In the event that the committee has no pending applications for review, the committee or its designees shall nonetheless convene to identify obstacles to domestic energy infrastructure specifically deriving from implementation of the ESA or the Marine Mammal Protection Act, to include regulatory reform efforts, species listings, and other related matters with the aim of developing procedural, regulatory, and interagency improvements.

Sec. 7. *Coordinated Infrastructure Assistance.* (a) In collaboration with the Secretaries of Interior and Energy, the Secretary of Defense shall conduct an assessment of the Department of Defense's ability to acquire and transport the energy, electricity, or fuels needed to protect the homeland and to conduct operations abroad, and, within 60 days, shall submit this assessment to the Assistant to the President for National Security Affairs. This assessment shall identify specific vulnerabilities, including, but not limited to, potentially insufficient transportation and refining infrastructure across the Nation, with a focus on such vulnerabilities within the Northeast and West Coast regions of the United States. The assessment shall also identify and recommend the requisite authorities and resources to remedy such vulnerabilities, consistent with applicable law.

(b) In accordance with section 301 of the National Emergencies Act (50 U.S.C. 1631), the construction authority provided in section 2808 of title 10, United States Code, is invoked and made available, according to its terms, to the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, to address any vulnerabilities identified in the assessment mandated by subsection (a). Any such recommended actions shall be submitted to the President for review, through the Assistant to the President for National Security Affairs and the Assistant to the President for Economic Policy.

Sec. 8. *Definitions.* For purposes of this order, the following definitions shall apply:

(a) The term ''energy'' or ''energy resources'' means crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. 1606 (a)(3).

(b) The term ''production'' means the extraction or creation of energy.

(c) The term ''transportation'' means the physical movement of energy, including through, but not limited to, pipelines.

(d) The term ''refining'' means the physical or chemical change of energy into a form that can be used by consumers or users, including, but not limited to, the creation of gasoline, diesel, ethanol, aviation fuel, or the beneficiation, enrichment, or purification of minerals.

(e) The term ''generation'' means the use of energy to produce electricity or thermal power and the transmission of electricity from its site of generation.

(f) The term ''energy supply'' means the production, transportation, refining, and generation of energy.

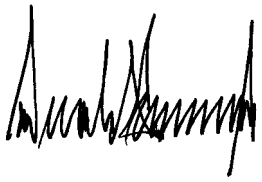
Sec. 9. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of OMB relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
January 20, 2025.

[FR Doc. 2025–02003
Filed 1–28–25; 11:15 am]
Billing code 3395–F4–P

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 93
Grid EO

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose.* The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy*. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority.* (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

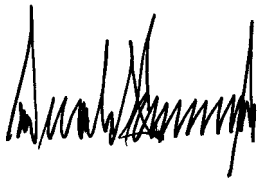
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 94
New York Times Coal Article

Trump Signs Orders Aimed at Reviving a Struggling Coal Industry

The moves include loosening environmental rules, but it is unclear how much they can help reverse the sharp decline in coal power over the last two decades.

Listen to this article · 7:58 min Learn more




By Brad Plumer and Mira Rojanasakul
Reporting from Washington

April 8, 2025

President Trump signed a flurry of executive orders Tuesday aimed at expanding the mining and burning of coal in the United States, in an effort to revive the struggling industry.

One order directs federal agencies to repeal any regulations that "discriminate" against coal production, to open new federal lands for coal mining and to explore whether coal-burning power plants could serve new A.I. data centers. Mr. Trump also said he would waive certain air-pollution restrictions adopted by the Biden administration for dozens of coal plants that were at risk of closing down.

In a move that could face legal challenges, Mr. Trump directed the Energy Department to develop a process for using emergency powers to prevent unprofitable coal plants from shutting down in order to avert power outages. Mr. Trump proposed a similar action in his first term but eventually abandoned the idea after widespread opposition.

Flanked by dozens of miners in white hard hats at the White House, Mr. Trump said he was also instructing the Justice Department to identify and fight state and local climate policies that were "putting our coal miners out of business." He added that he would issue "guarantees" that future administrations could not adopt policies harmful to coal, but did not provide details.

“This is a very important day to me because we’re bringing back an industry that was abandoned despite the fact that it was the best, certainly the best in terms of power, real power,” Mr. Trump said.

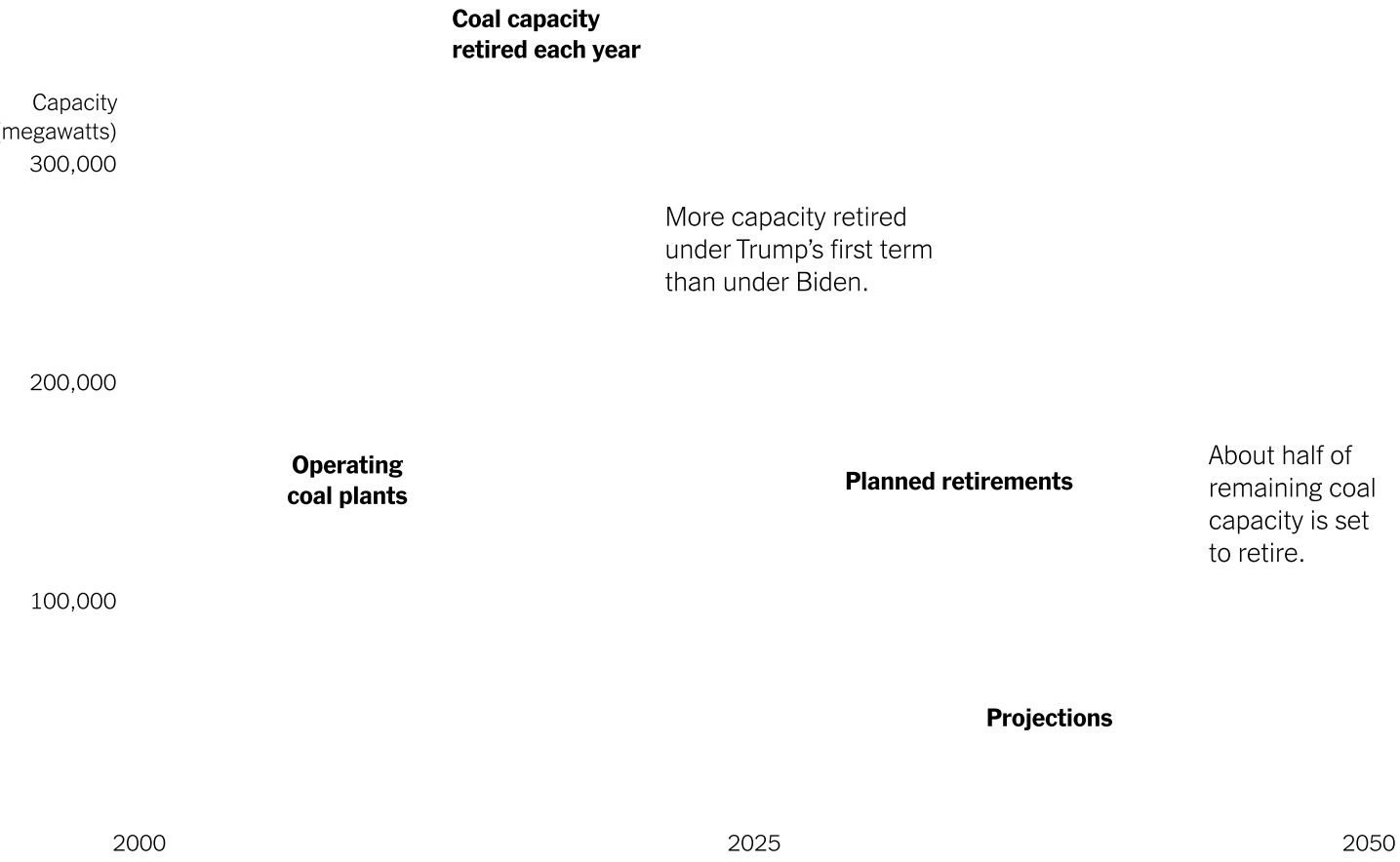
In recent weeks, Mr. Trump, Chris Wright, the energy secretary, and Doug Burgum, the interior secretary, have all spoken about the importance of coal. The two cabinet members sat in the front row at the White House ceremony, which was attended by members of Congress from Wyoming, Kentucky, West Virginia and other coal-producing states.

“Beautiful clean coal,” Mr. Trump told the gathering. “Never use the word ‘coal’ unless you put ‘beautiful, clean’ before it.”

Coal is the most polluting of all fossil fuels when burned, and accounts for roughly 40 percent of the world’s industrial carbon dioxide emissions, the main driver of global warming. It releases other pollutants, including mercury and sulfur dioxide, that are linked to heart disease, respiratory problems and premature deaths. Coal mining and the resulting coal ash from power plants can also present environmental problems.

Over the past two decades, the use of coal has fallen precipitously in the United States, as utilities have switched to cheaper and cleaner electricity sources like natural gas, wind and solar power. That transition has been the biggest reason for the drop in U.S. emissions since 2005.

Coal power has declined sharply — and more retirements are coming.



Source: Global Energy Monitor and New York Times reporting. • Note: Includes coal capacity added. • By Mira Rojanasakul/The New York times

It is unclear how much Mr. Trump could reverse that decline. In 2011, the nation generated nearly half of its electricity from coal; last year, that fell to just 15 percent. Utilities have already closed hundreds of aging coal-burning units and have announced retirement dates for roughly half of the remaining plants.

In recent years, growing interest in artificial intelligence and data centers has fueled a surge in electricity demand, and utilities have decided to keep more than 50 coal-burning units open past their scheduled closure dates, according to America's Power, an industry trade group. And as the Trump administration moves to loosen pollution limits on coal power — including regulations applied to carbon dioxide and mercury — more plants could stay open longer, or run more frequently.

"You know, we need to do the A.I., all of this new technology that's coming on line," Mr. Trump said on Tuesday. "We need more than double the energy, the electricity, that we currently have."

Yet a major coal revival is unlikely, some analysts said.

“The main issue is that most of our coal plants are older and getting more expensive to run, and no one’s thinking about building new plants,” said Seth Feaster, a data analyst who focuses on coal at the Institute for Energy Economics and Financial Analysis, a research firm. “It’s very hard to change that trajectory.”

During his first term, Mr. Trump sought to prevent unprofitable coal plants from closing, using emergency authority that is normally reserved for fleeting crises like natural disasters. But that idea brought a fierce blowback from oil and gas companies, grid operators and consumer groups, who said it would drive up electricity bills, and the administration eventually backed away from the idea.

If the idea was tried again today, it would be likely to lead to lawsuits, said Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School. “But there’s not a lot of litigation history here,” he said. “Typically these emergency orders last for no longer than 90 days.”

Ultimately, Mr. Trump struggled to fulfill his first-term pledge of rescuing the coal industry. Despite the fact that his administration repealed numerous climate regulations and appointed a coal lobbyist to lead the Environmental Protection Agency, 75 coal-fired power plants closed, and the industry shed about 13,000 jobs during his presidency.

Coal’s decline continued under President Joseph R. Biden Jr., who sought to move the country away from the fossil fuel altogether in an effort to fight climate change. Last year, his administration issued a sweeping E.P.A. rule that would have forced all of the nation’s coal plants to either install expensive equipment to capture and bury their carbon dioxide emissions or shut down by 2039.

This year, upon returning to office, Mr. Trump ordered the E.P.A. to repeal that rule. And Trump administration officials have repeatedly warned that shutting down coal plants would harm power supplies. Unlike wind and solar energy, coal plants can run at any hour of the day, making them useful when electricity demand spikes.

Some industry executives who run the nation’s electric grids have also warned that the country could face a greater risk of blackouts if too many coal plants retire too quickly, especially since power companies have faced delays in bringing new gas, wind and solar plants online, as well as in adding battery storage and transmission lines.

“For decades, most people have taken electricity and coal for granted,” said Michelle Bloodworth, chief executive of America’s Power. “This complacency has led to damaging federal and state policies that have caused the premature retirement of coal plants, thus weakening our electric grid and threatening our national security.”

Yet coal opponents say that keeping aging plants online can worsen deadly air pollution and increase energy costs. Earlier this year, PJM Interconnection, which oversees a large grid in the Mid-Atlantic, ordered a power plant that burns coal and another that burns oil to stay open until 2029, four years past their planned retirement date, to reduce the risk of power outages. The move could ultimately cost utility customers in the area of more than $720 million.

“Coal plants are old and dirty, uncompetitive and unreliable,” said Kit Kennedy, managing director for power at the Natural Resources Defense Council, an environmental group. “The Trump administration is stuck in the past, trying to make utility customers pay more for yesterday’s energy. Instead, it should be doing all it can to build the electricity grid of the future.”

Brad Plumer is a Times reporter who covers technology and policy efforts to address global warming.

Mira Rojanasakul is a Times reporter who uses data and graphics to cover climate and the environment.

A version of this article appears in print on , Section A, Page 15 of the New York edition with the headline: Trump Signs Orders Aimed At Reviving Coal Industry

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 95
EIA Table 8.4

U.S. Energy Information Administration

Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 2014 through 2024 (Mills per Kilowatthour)

	Operation				Maintenance			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	12.41	4.55	7.30	2.63	6.67	5.11	4.59	2.90
2015	11.17	5.16	8.37	2.34	7.06	5.41	5.06	2.68
2016	10.90	5.05	6.65	2.49	7.01	5.53	4.34	2.74
2017	10.27	5.01	6.33	2.45	6.63	5.13	3.96	2.83
2018	10.78	5.19	6.69	2.37	5.93	5.27	3.96	2.71
2019	10.63	5.52	6.86	2.58	6.29	6.85	3.94	2.64
2020	10.05	6.40	7.72	2.38	5.78	5.60	5.00	2.51
2021	10.55	5.70	7.98	2.12	5.88	5.32	4.33	2.28
2022	10.51	6.75	7.68	2.20	6.10	5.09	4.76	2.36
2023	9.52	6.48	9.18	2.16	6.36	5.61	5.53	2.12
2024	9.87	6.98	8.97	2.25	6.84	5.81	6.10	2.11

	Fuel				Total			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	7.71	29.39	--	37.06	26.79	39.04	11.90	42.60
2015	7.48	26.70	--	28.22	25.71	37.26	13.42	33.24
2016	7.45	25.50	--	24.97	25.36	36.08	10.98	30.19
2017	7.47	25.27	--	26.48	24.38	35.41	10.29	31.76
2018	7.15	25.40	--	27.35	23.86	35.86	10.65	32.43
2019	6.81	24.28	--	23.11	23.73	36.66	10.80	28.33
2020	6.10	22.87	--	19.65	21.92	34.86	12.71	24.55
2021	6.31	24.64	--	25.78	22.74	35.66	12.30	30.18
2022	6.12	32.04	--	38.72	22.73	43.88	12.44	43.28
2023	6.12	30.58	--	22.19	22.00	42.67	14.71	26.47
2024	6.37	28.52	--	18.59	23.08	41.32	15.07	22.95

Hydroelectric category consists of both conventional hydroelectric and pumped storage.
Gas Turbine and Small Scale category consists of gas turbine, internal combustion, photovoltaic, and wind plants.
Notes: Expenses are average expenses weighted by net generation. A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of one cent).
Total may not equal sum of components due to independent rounding.
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 96
July Resource Adequacy Report

U.S. DEPARTMENT of ENERGY



Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation’s power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored “call to action” for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

Table of Contents

Acknowledgments i
Background to this Report vi
Executive Summary 1
1 Modeling Methodology 10
1.1 Modeling Resource Adequacy 13
1.2 Planning Years and Weather Years 15
1.3 Load Modeling 15
1.4 Transfer Capabilities and Import Export Modeling 18
1.5 Perfect Capacity Additions 19
2 Regional Analysis 20
2.1 MISO 20
2.2 ISO-NE 23
2.3 NYISO 25
2.4 PJM 27
2.5 SERC 30
2.6 SPP ..... **Error! Bookmark not defined.**
2.7 CAISO+ 35
2.8 West Non-CAISO 37
2.9 ERCOT 40
Appendix A - Generation Calibration and Forecast A-1
Appendix B - Representing Canadian Transfer Limits B-1
References C-1
EO 14262 ..... C-3

List of Figures

Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures 6
Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures 6
Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures 8
Figure 4. Tuned Perfect Capacity (MW) By Region 9
Figure 5. TPRs used in NERC ITCS 10
Figure 6. Simplified Overview of Model 14
Figure 7. 2024 to 2030 Projected Data Center Load Additions 16
Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated) 17
Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case) 18
Figure 10. MISO Max Daily Load in the Current System versus 2030 21
Figure 11. MISO Generation Capacity by Technology and Scenario 21
Figure 12. ISO-NE Max Daily Load in the Current System versus 2030 23
Figure 13. ISO-NE Generation Capacity by Technology and Scenario 24
Figure 14. NYISO Max Daily Load in the Current System versus 2030 25
Figure 15. NYISO Generation Capacity by Technology and Scenario 26
Figure 16. PJM Max Daily Load in the Current System versus 2030 28
Figure 17. PJM Generation Capacity by Technology and Scenario 28
Figure 18. SERC Max Daily Load in the Current System versus 2030 30
Figure 19. SERC Generation Capacity by Technology and Scenario 31
Figure 20. SPP Max Daily Load in the Current System versus 2030 33
Figure 21. SPP Generation Capacity by Technology and Scenario 33
Figure 22. CAISO+ Max Daily Load in the Current System versus 2030 35
Figure 23. CAISO+ Generation Capacity by Technology and Scenario 36
Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030 38
Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario 38
Figure 26. ERCOT Max Daily Load in the Current System versus 2030 41
Figure 27. ERCOT Generation Capacity by Technology and Scenario 41

List of Tables

Table 1. Summary Metrics Across Cases 7
Table 2. Summary of MISO Reliability Metrics 20
Table 3. Nameplate Capacity by MISO Subregion and Technology (MW) 22
Table 4. Summary of ISO-NE Reliability Metrics 23
Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW) 24
Table 6. Summary of NYISO Reliability Metrics 25
Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW) 26
Table 8. Summary of PJM Reliability Metrics 27
Table 9. Nameplate Capacity by PJM Subregion and Technology (MW) 29
Table 10. Summary of SERC Reliability Metrics 30
Table 11. Nameplate Capacity by SERC Subregion and Technology (MW) 31
Table 12. Summary of SPP Reliability Metrics 32
Table 13. Nameplate Capacity by SPP Subregion and Technology (MW) 34
Table 14. Summary of CAISO+ Reliability Metrics 35
Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW) 36
Table 16. Summary of West Non-CAISO Reliability Metrics 37
Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW) 39
Table 18. Summary of ERCOT Reliability Metrics 40
Table 19. Nameplate Capacity for ERCOT and by Technology (MW) 42

Additional figures and tables in appendices

List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

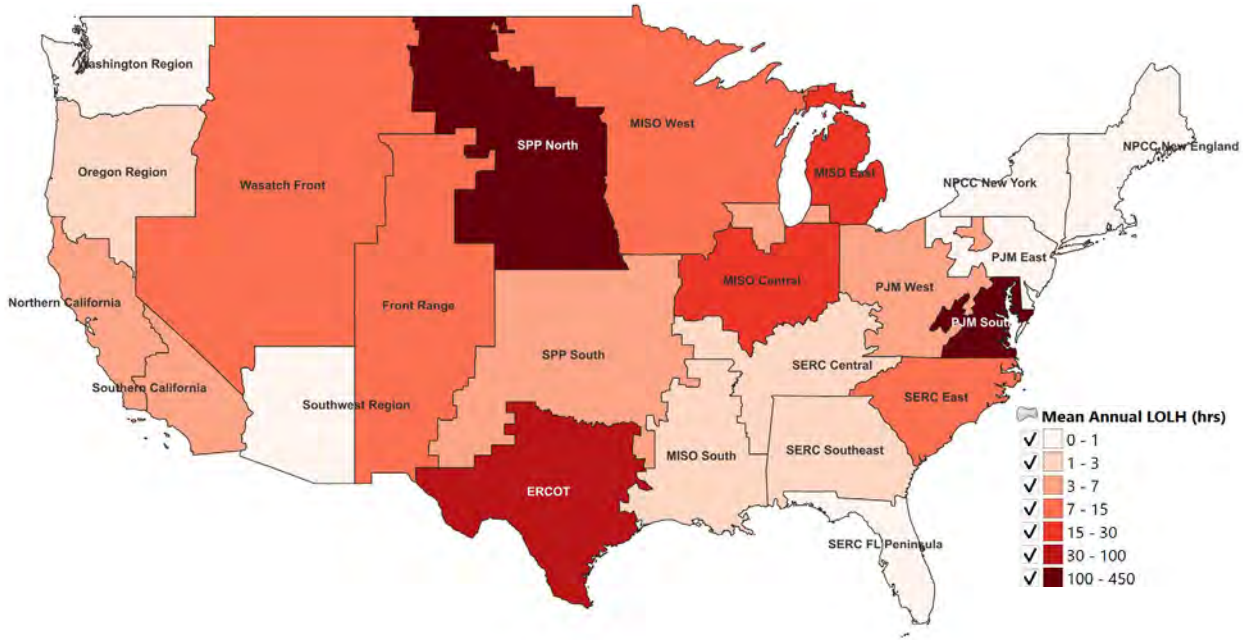


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

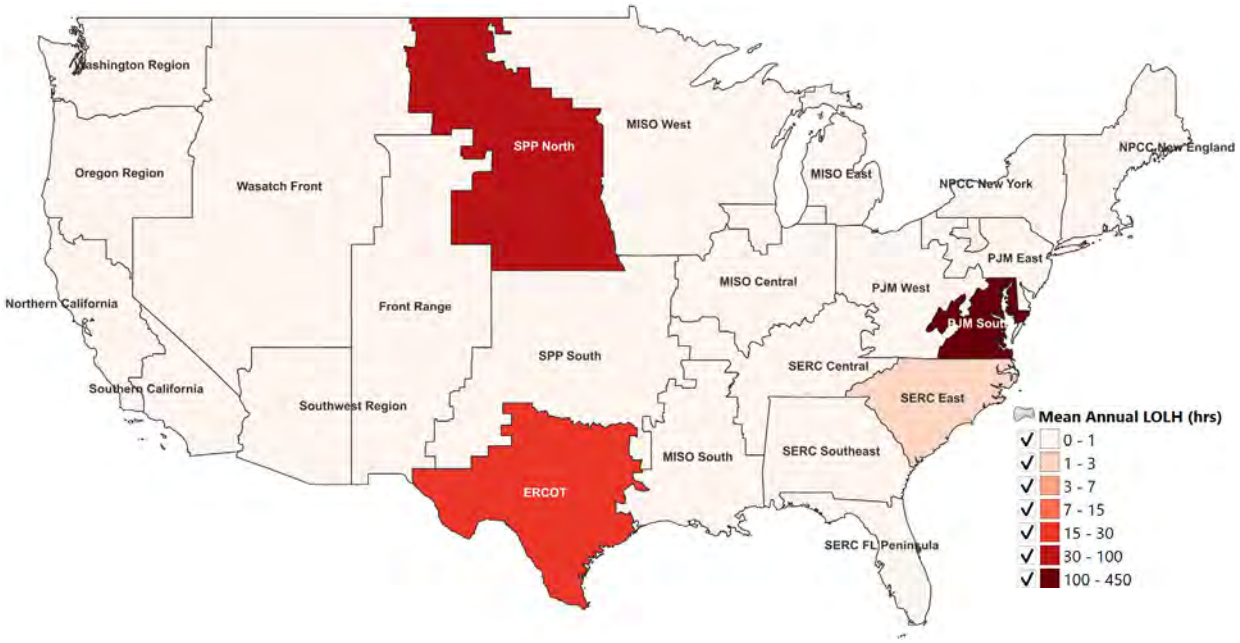


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

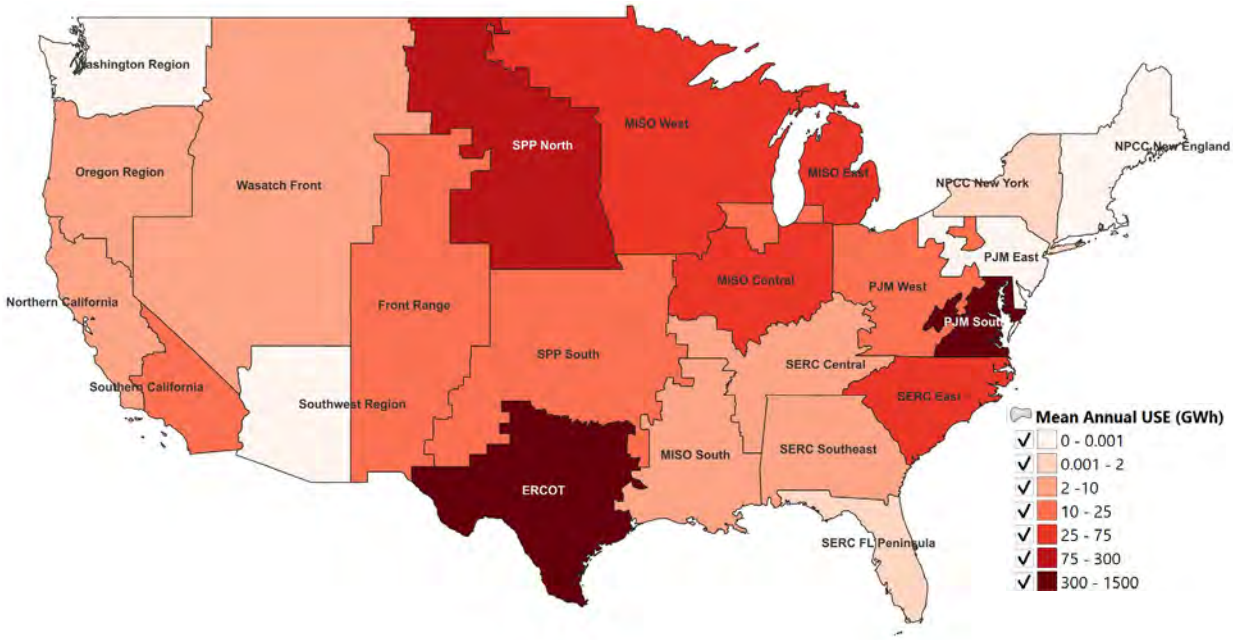


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

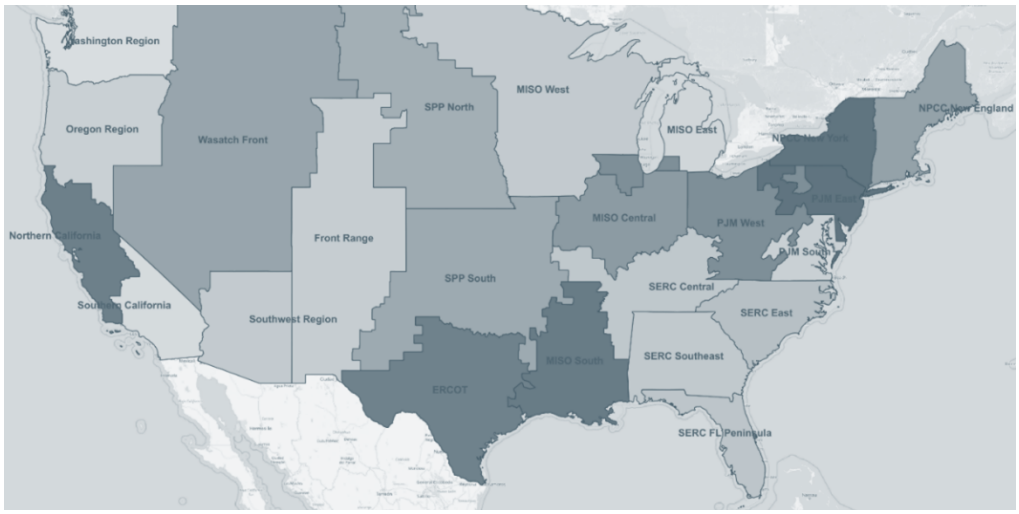


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]

  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

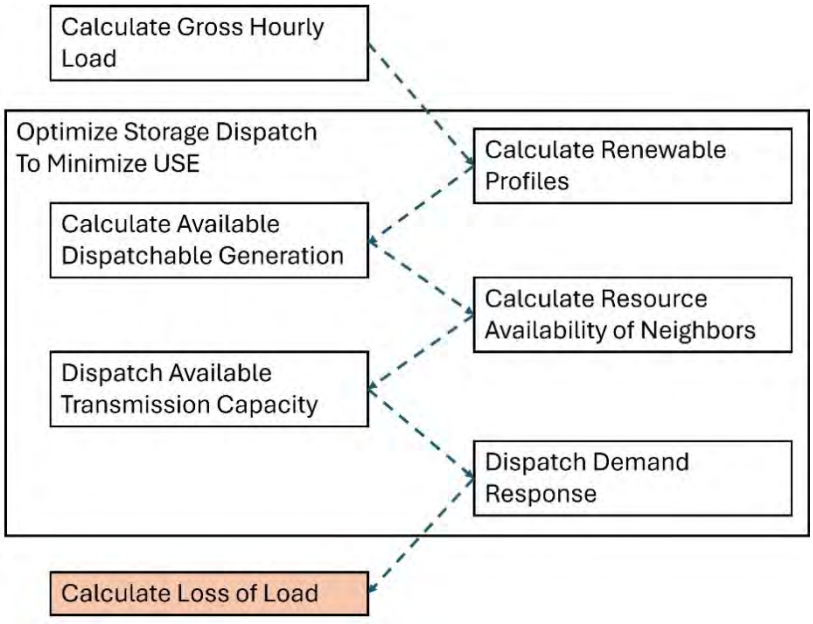


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

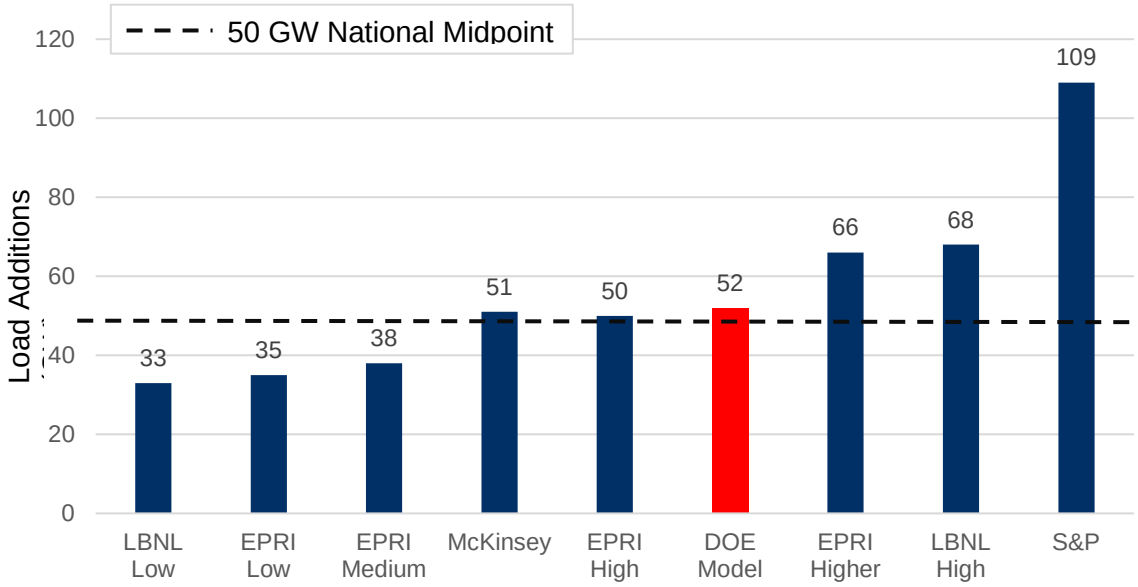


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

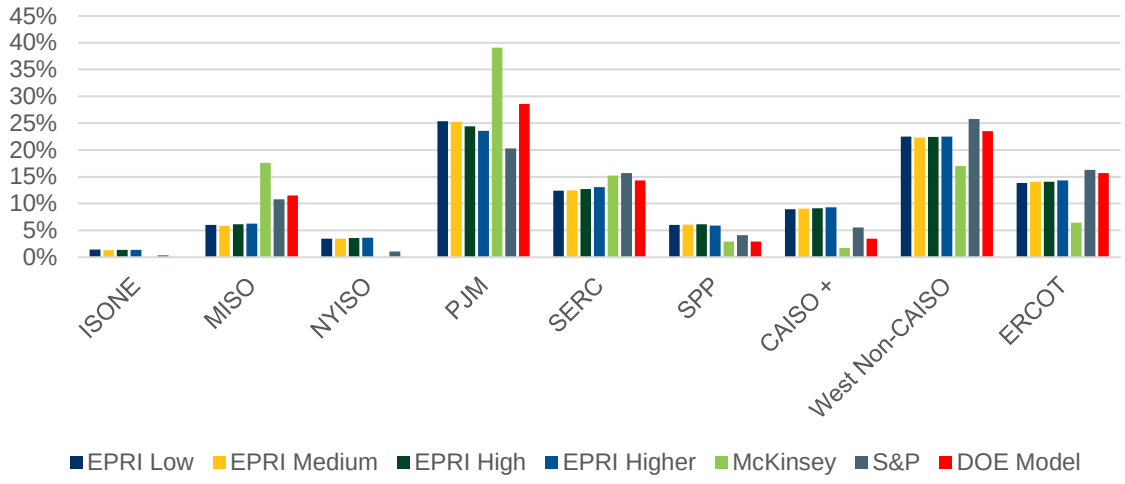


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

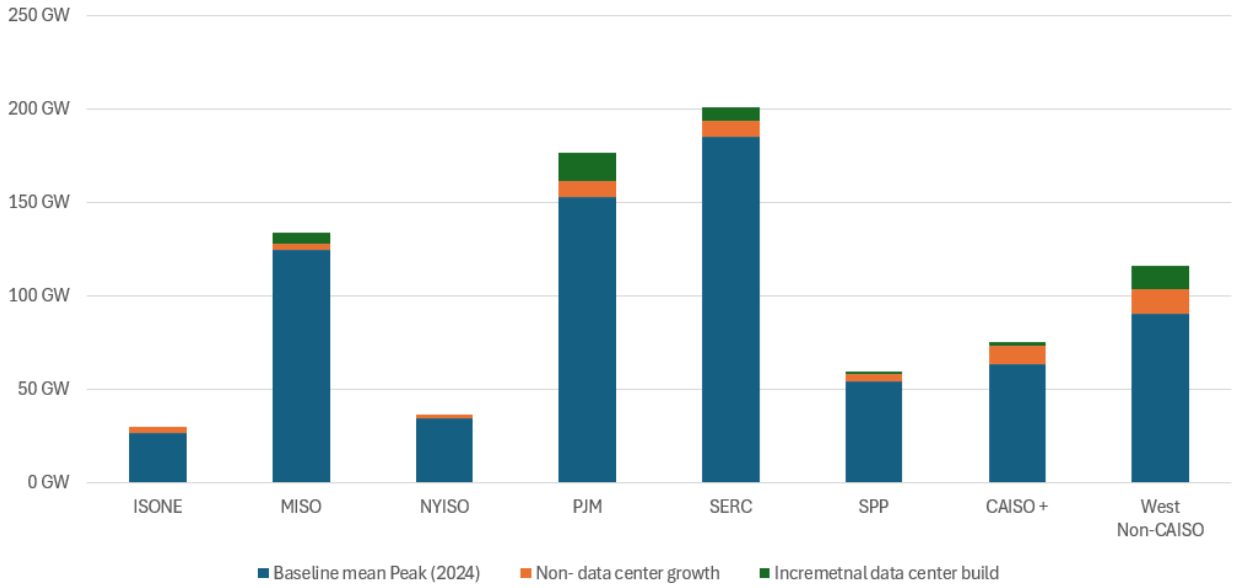


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

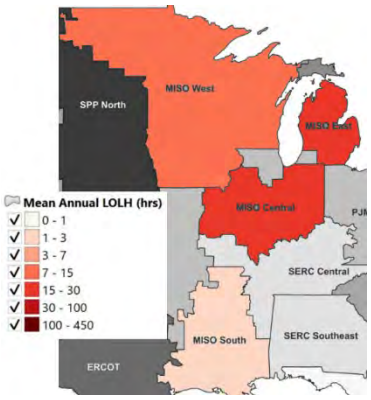


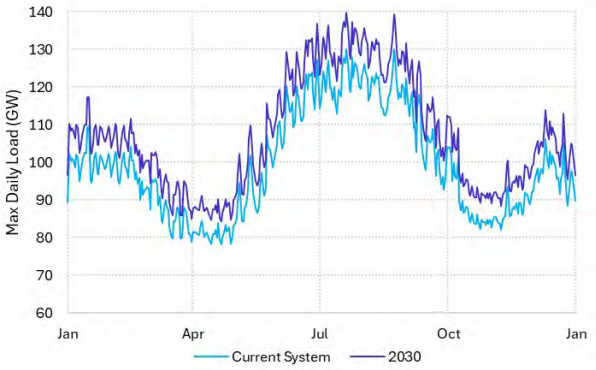
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

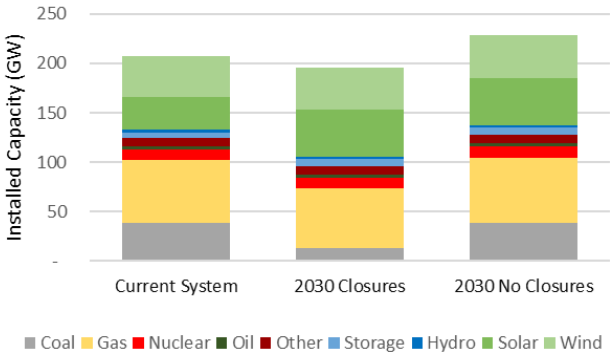


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

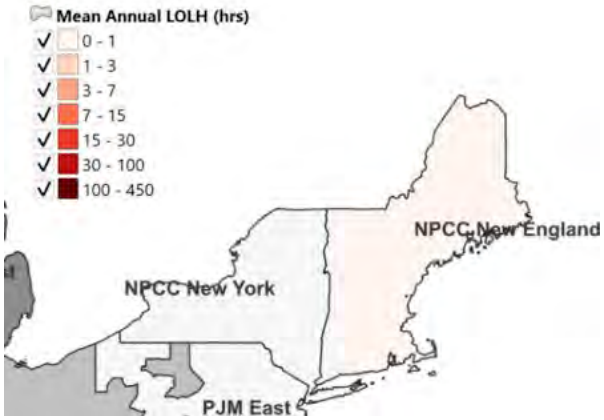
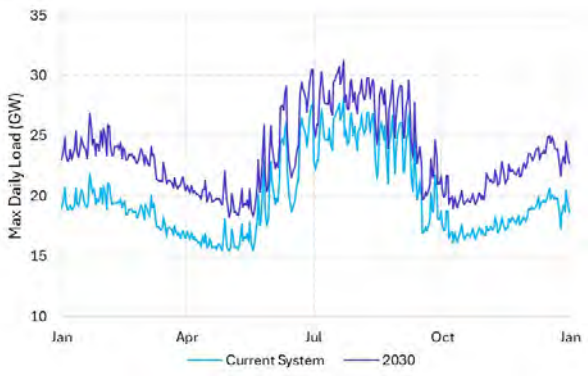


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	**28,128**	**31,261**

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

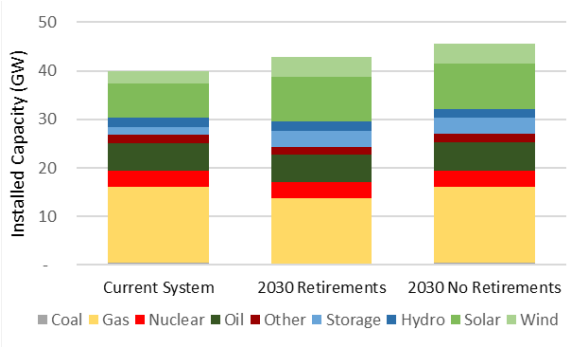


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

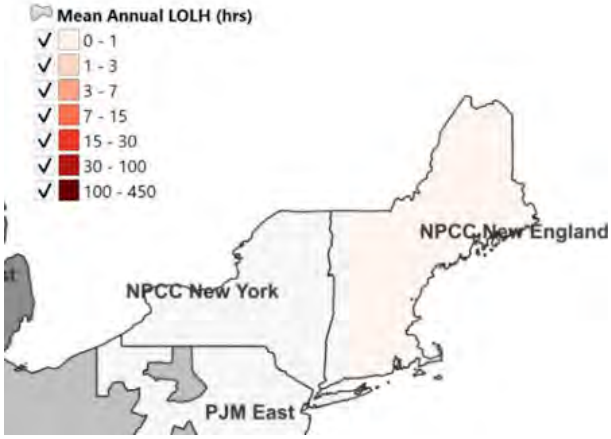
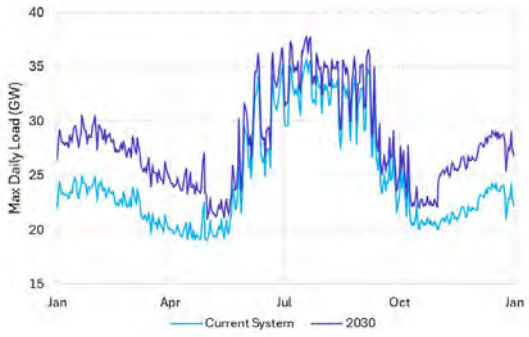


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

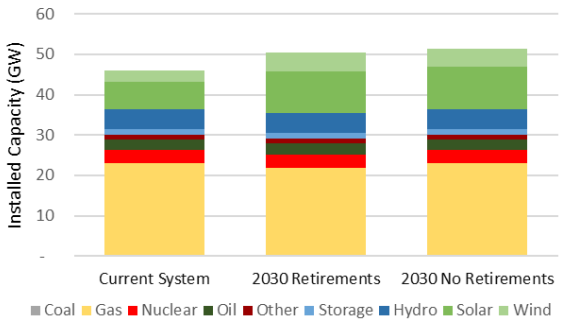


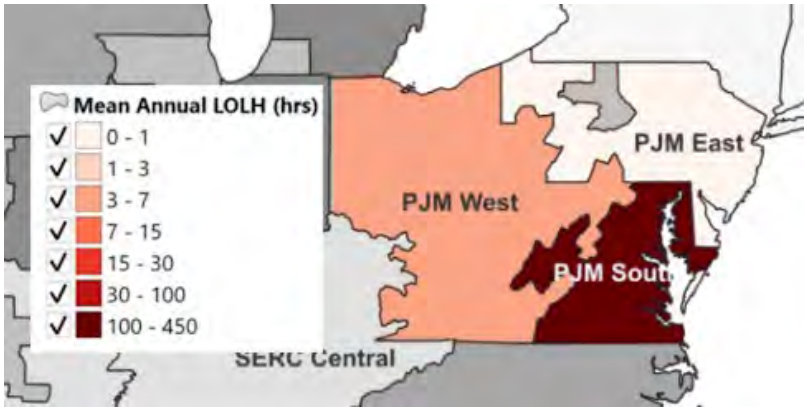
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



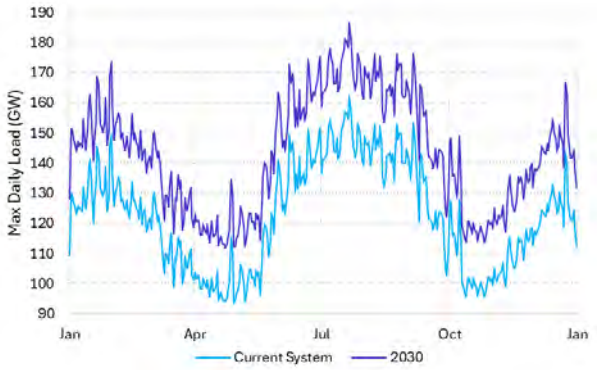
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

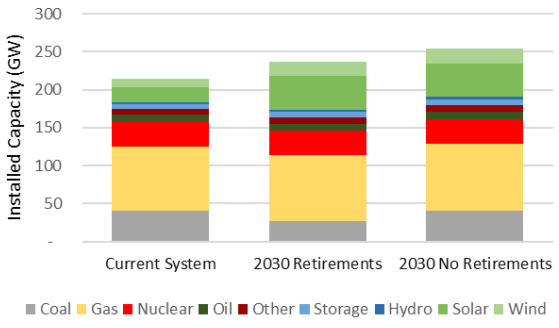


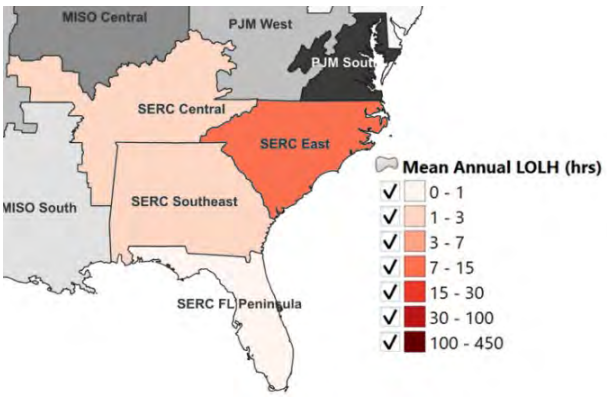
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



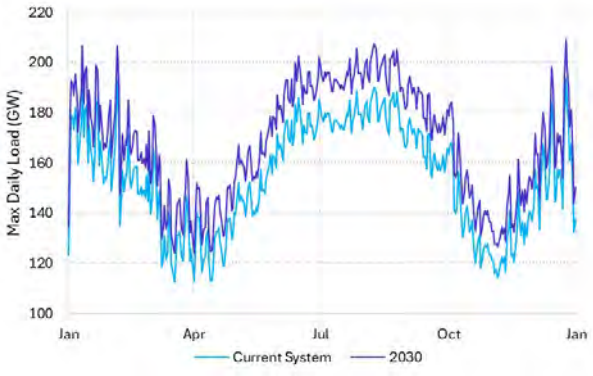
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	**193,654**	**209,269**

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

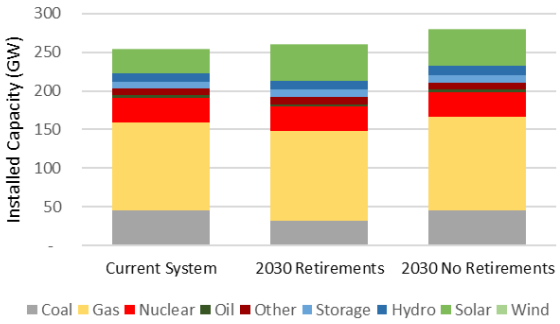


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

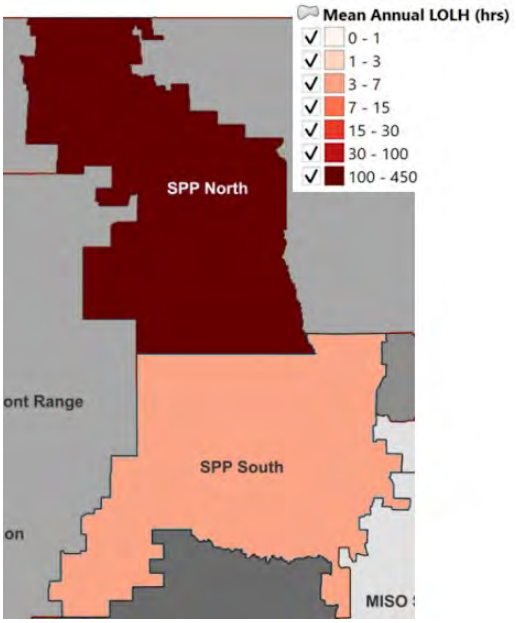
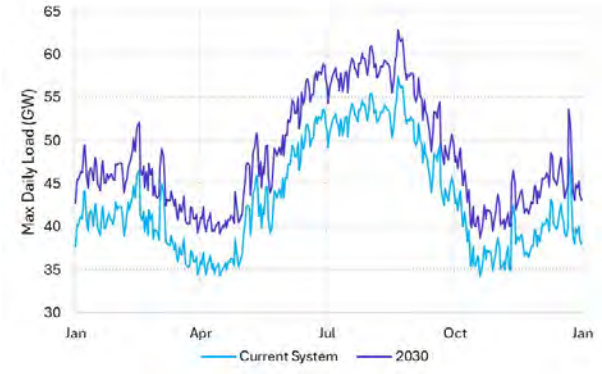


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

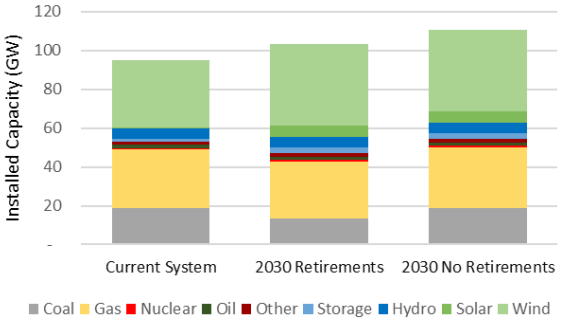


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

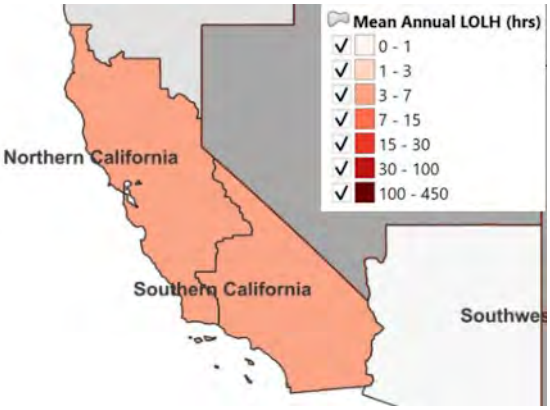
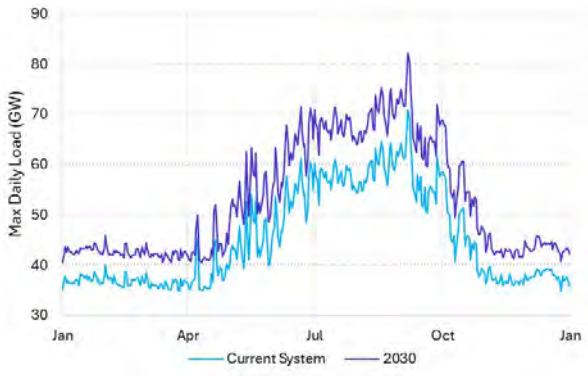


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

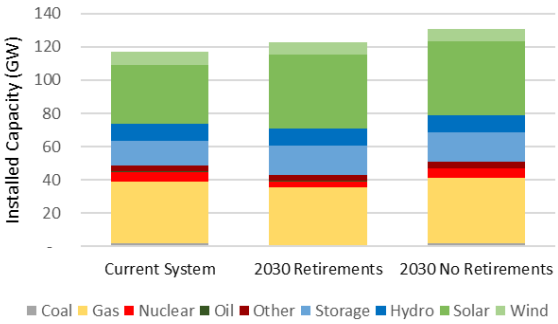


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

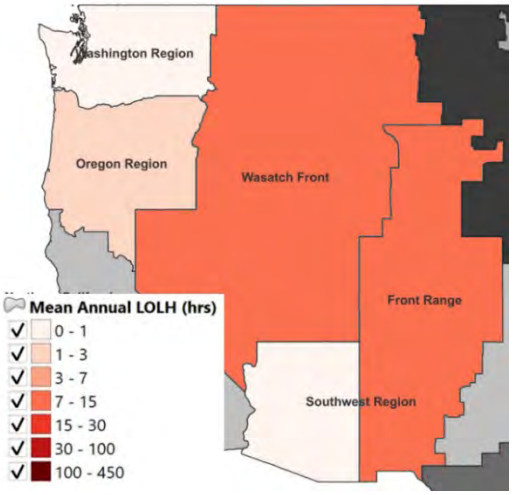
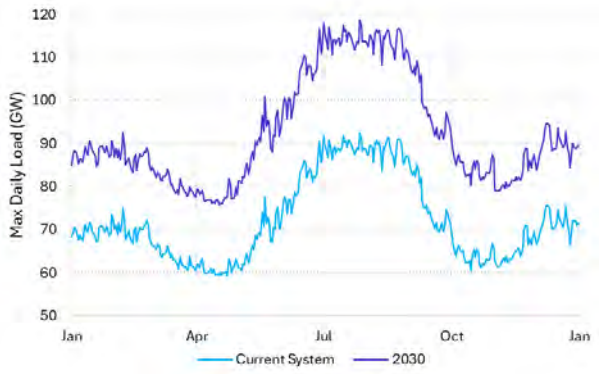


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	**92,448**	**118,657**

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	**177,929**	**193,485**	**206,908**

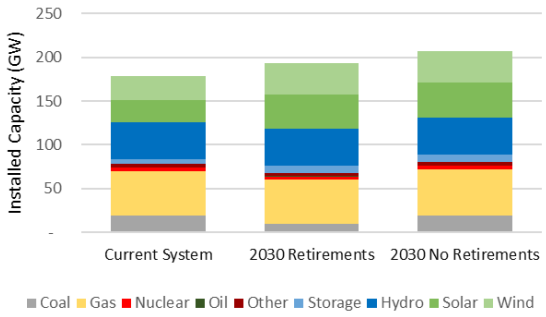


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

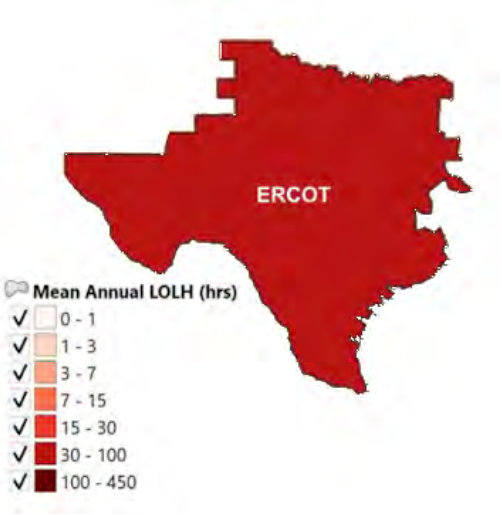
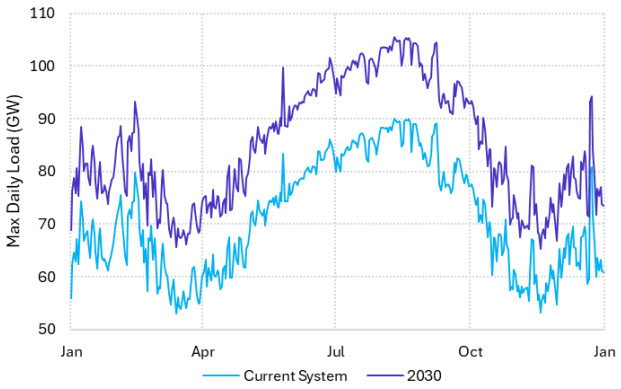


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

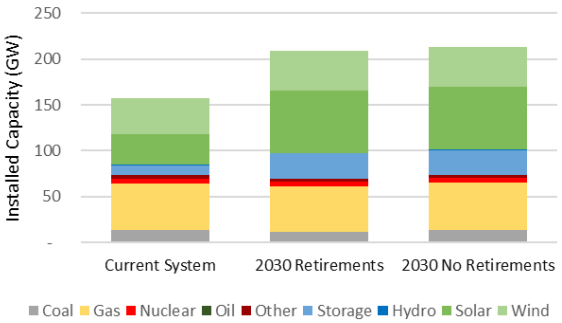


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).” https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

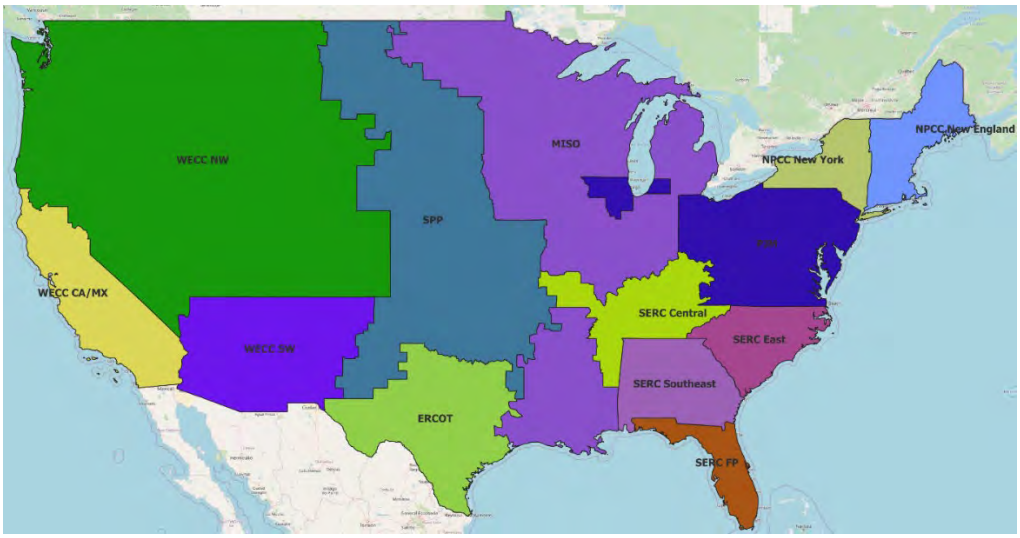


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \qquad \textit{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	**178,268**	**468,635**	**97,169**	**27,610**	**5,353**	**4,093**	**1,096**	**24,144**	**29,256**	**82,249**	**147,856**	**168,966**	**31,161**	**43,169**	**1,309,026**

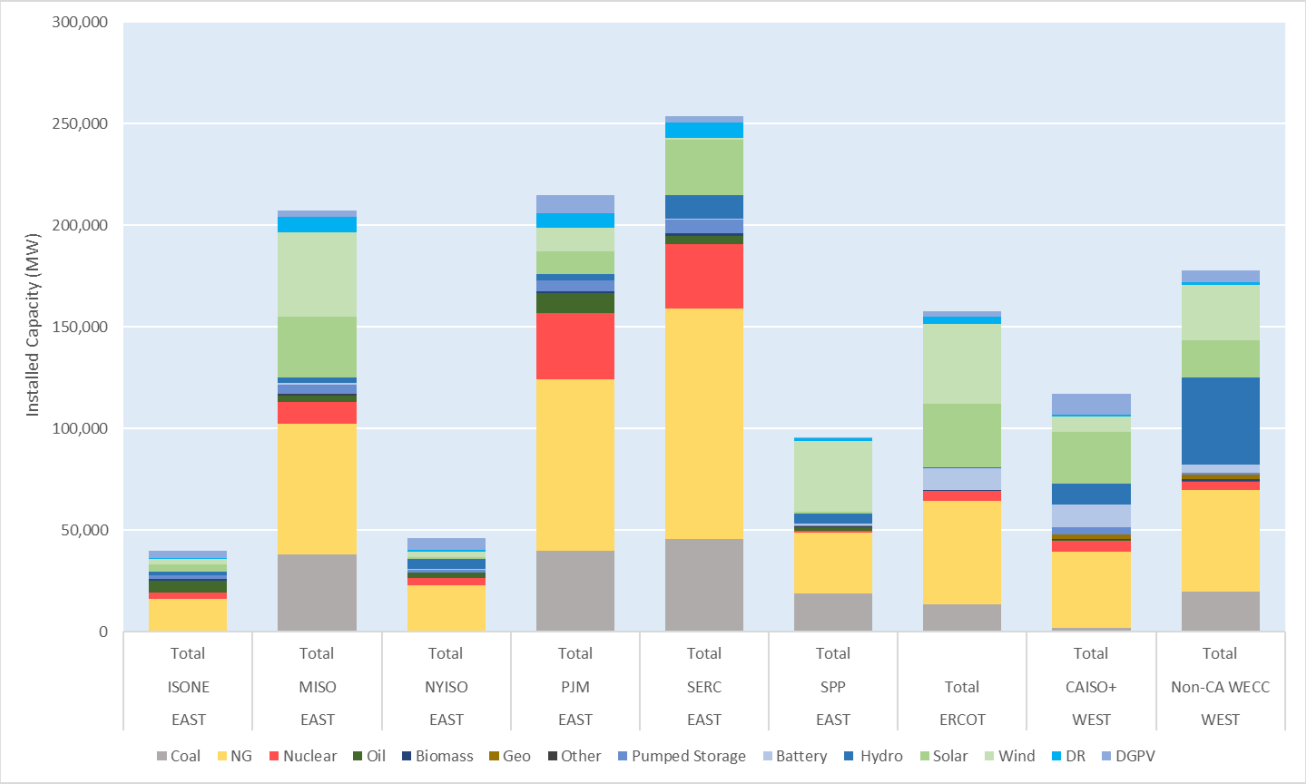


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

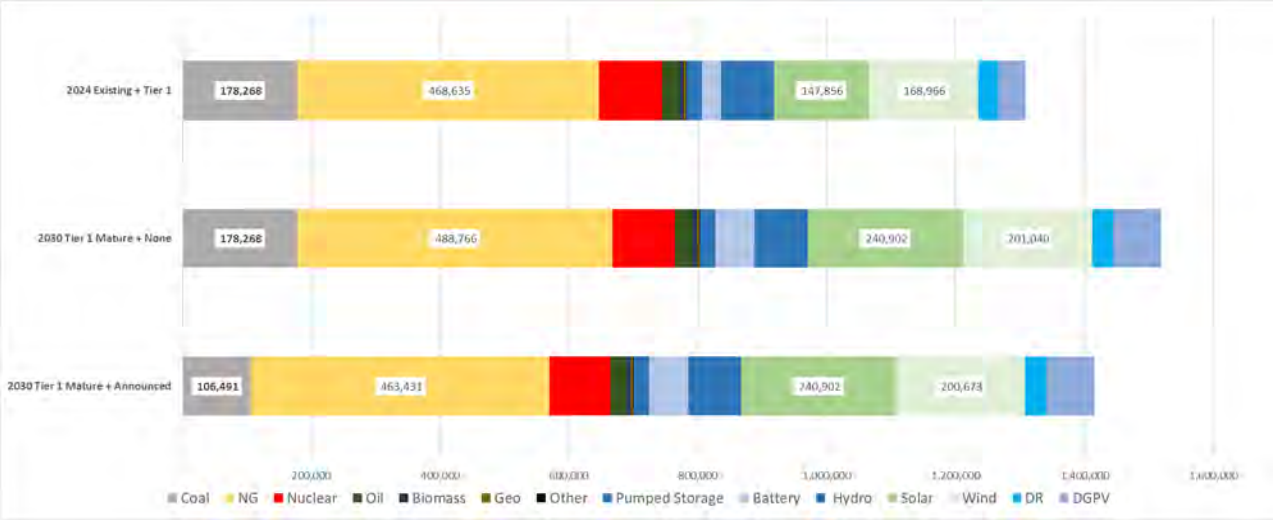


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a "learning rate" scales each tree's contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

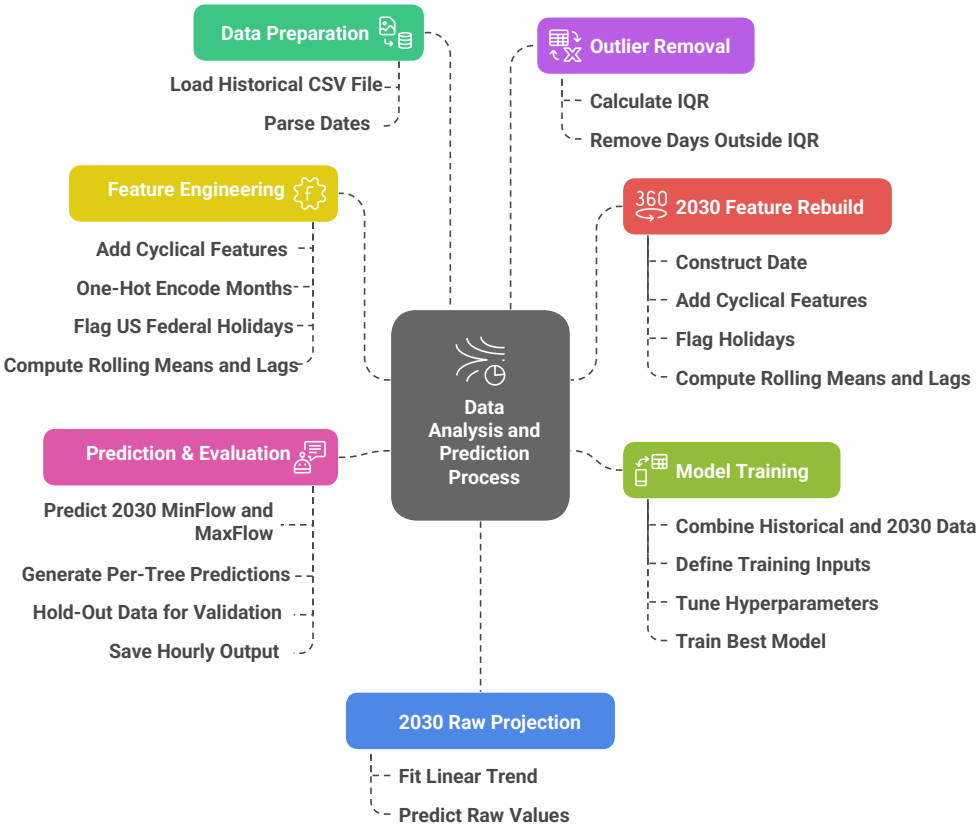


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year's MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

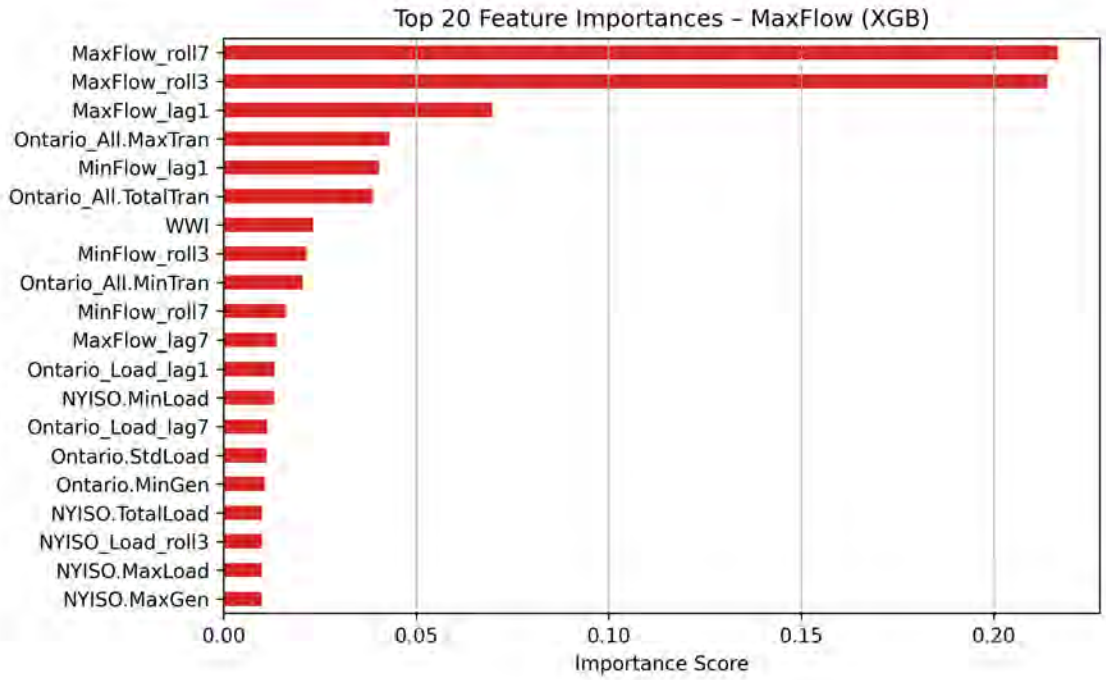


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

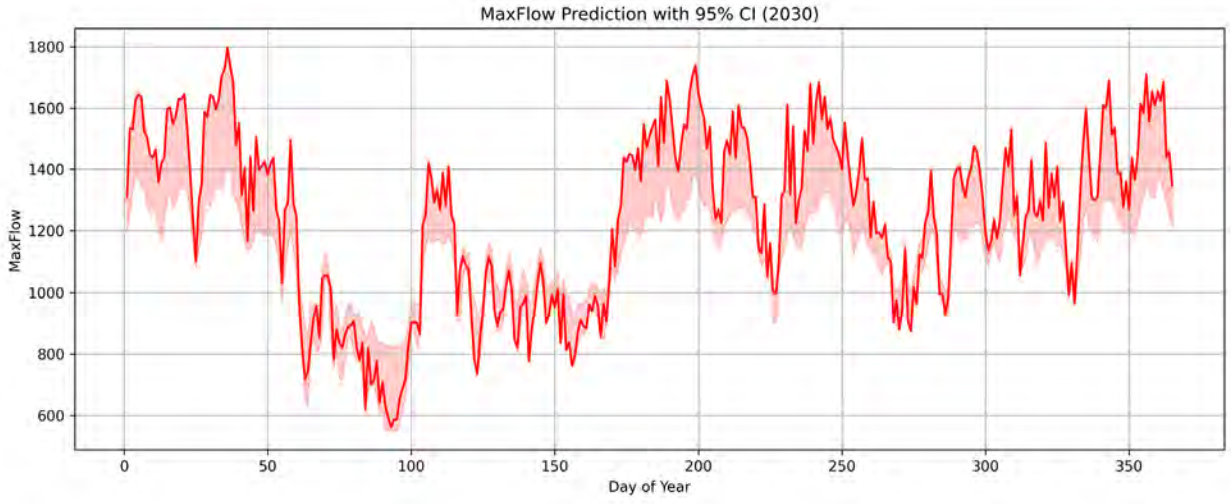


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

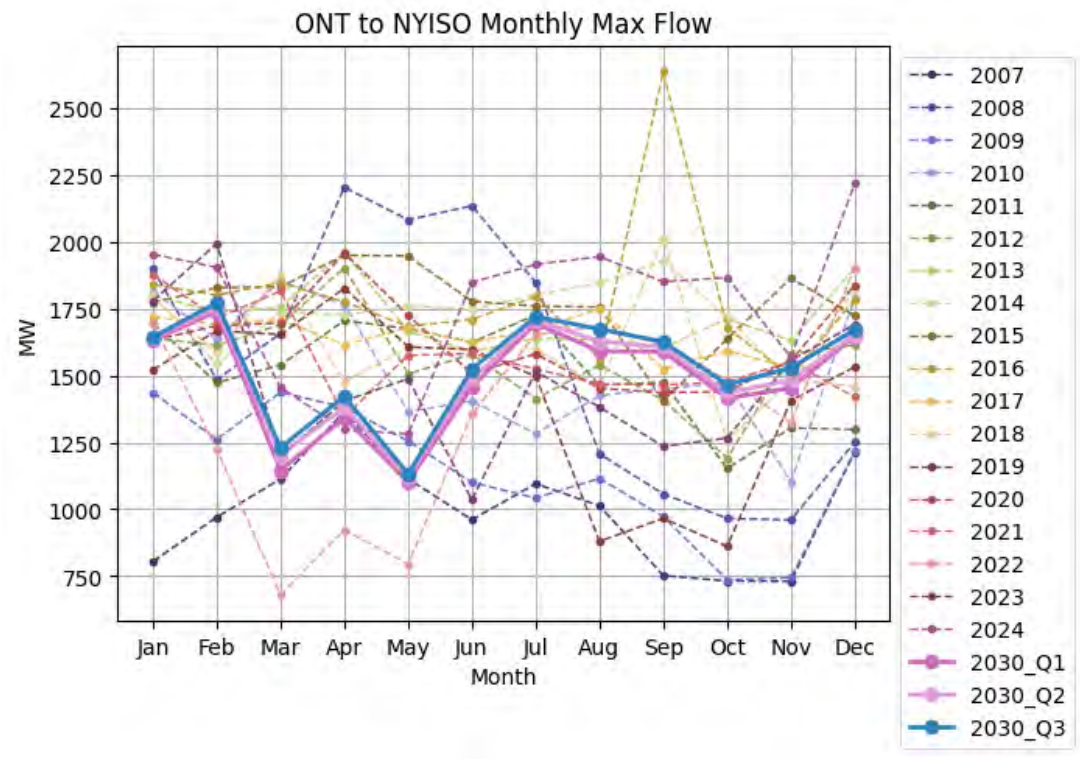


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

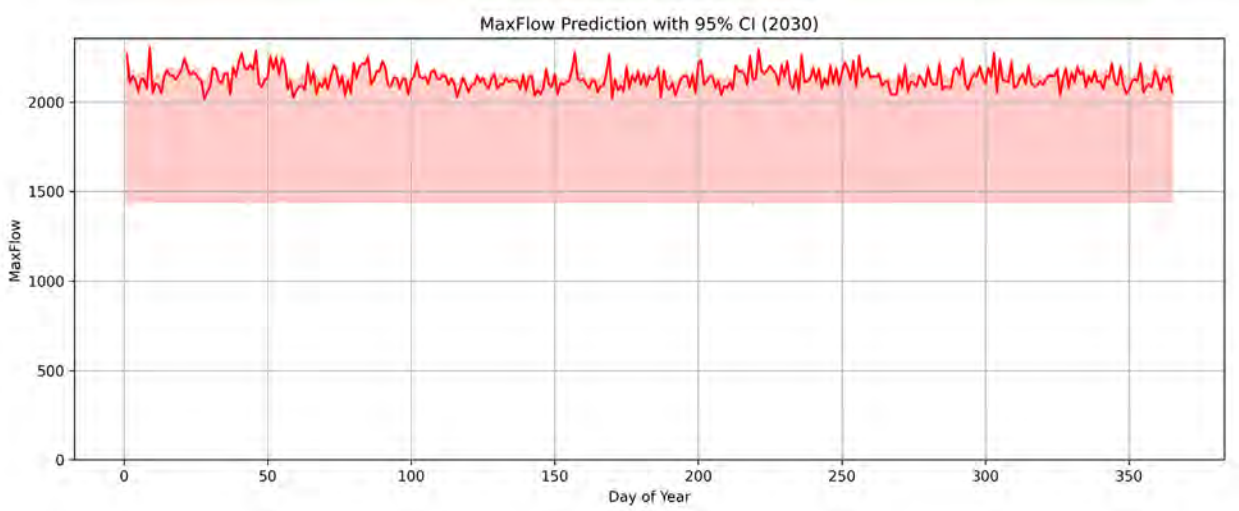


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

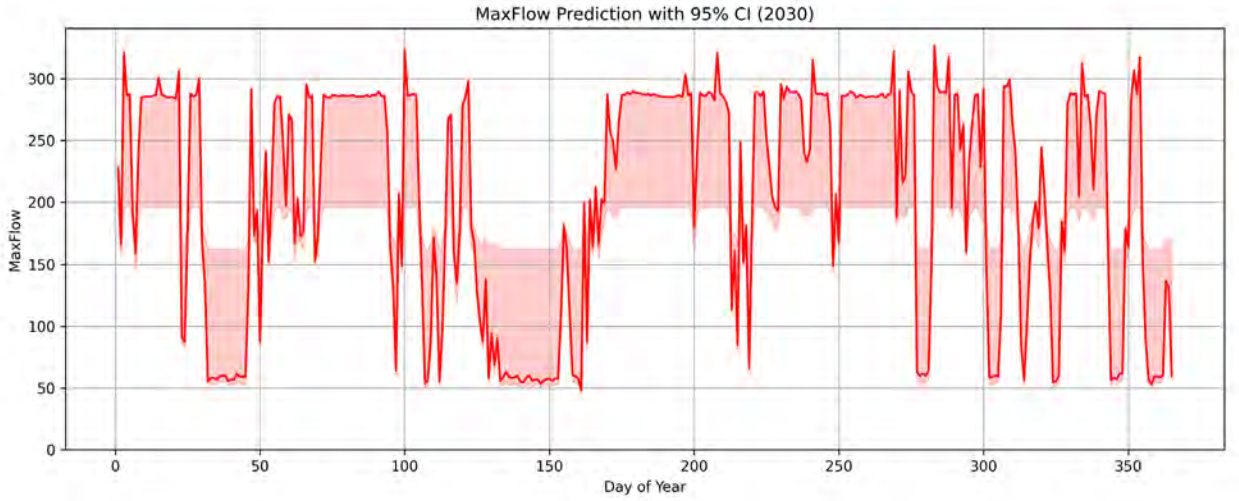


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

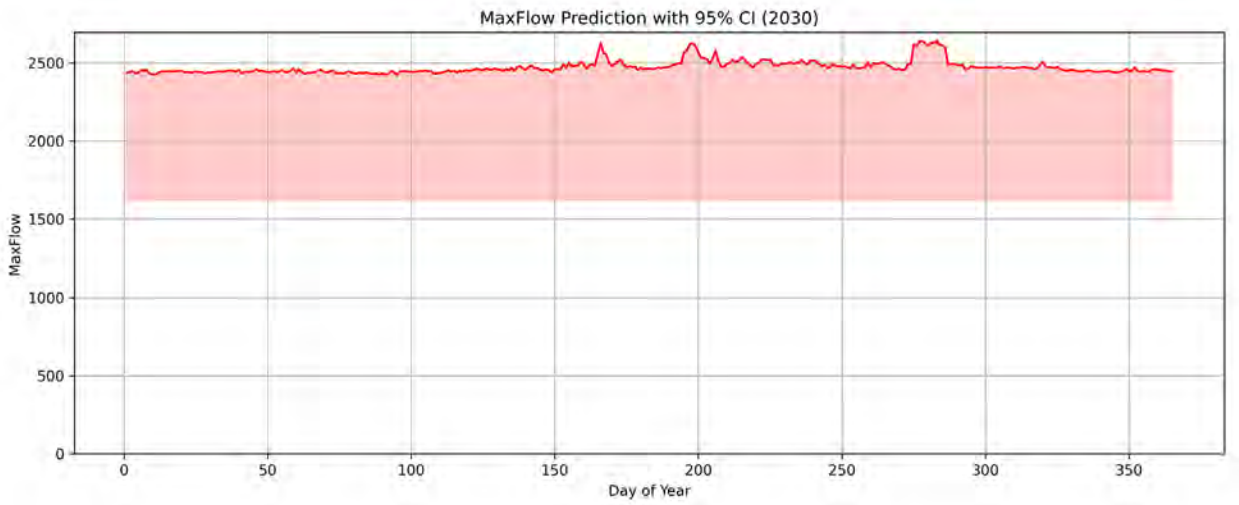


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

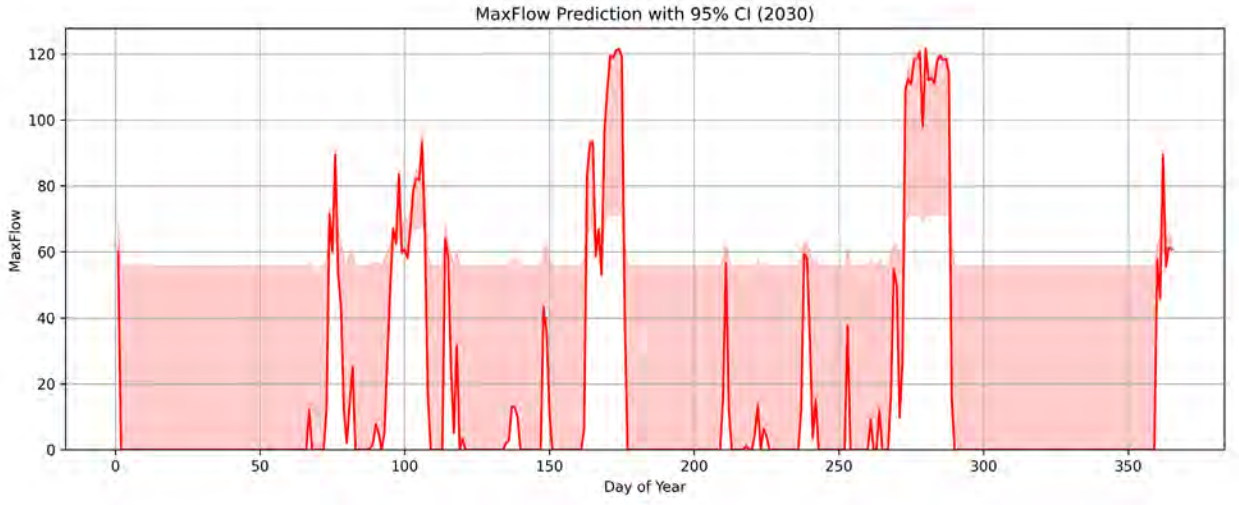


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

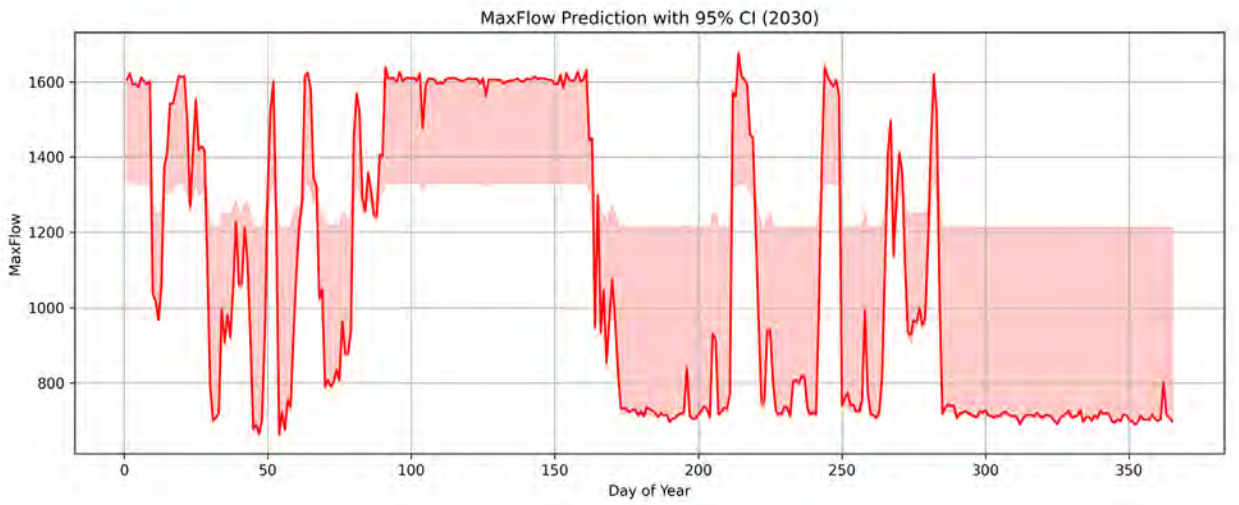


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

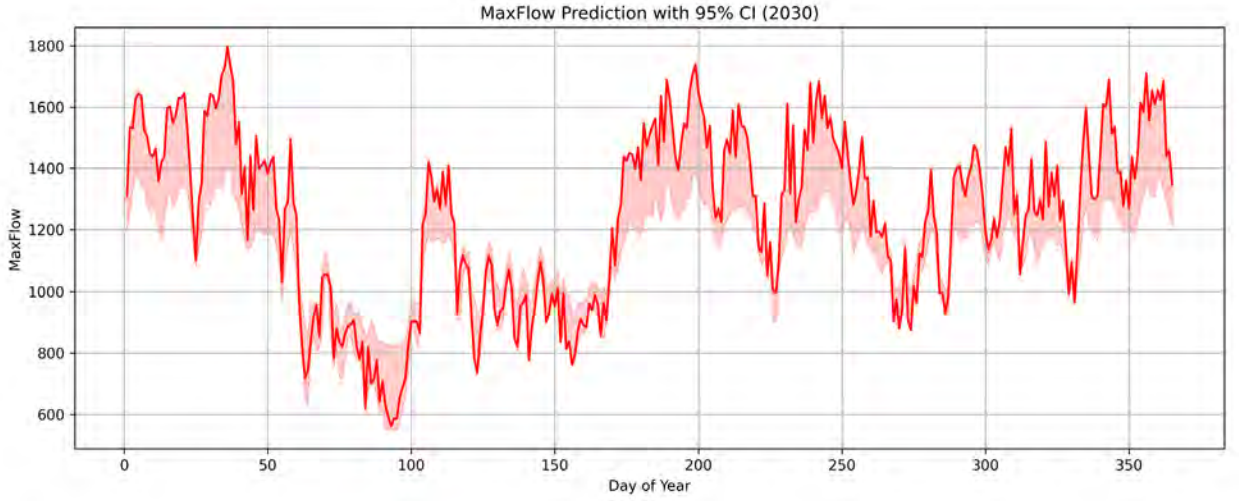


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

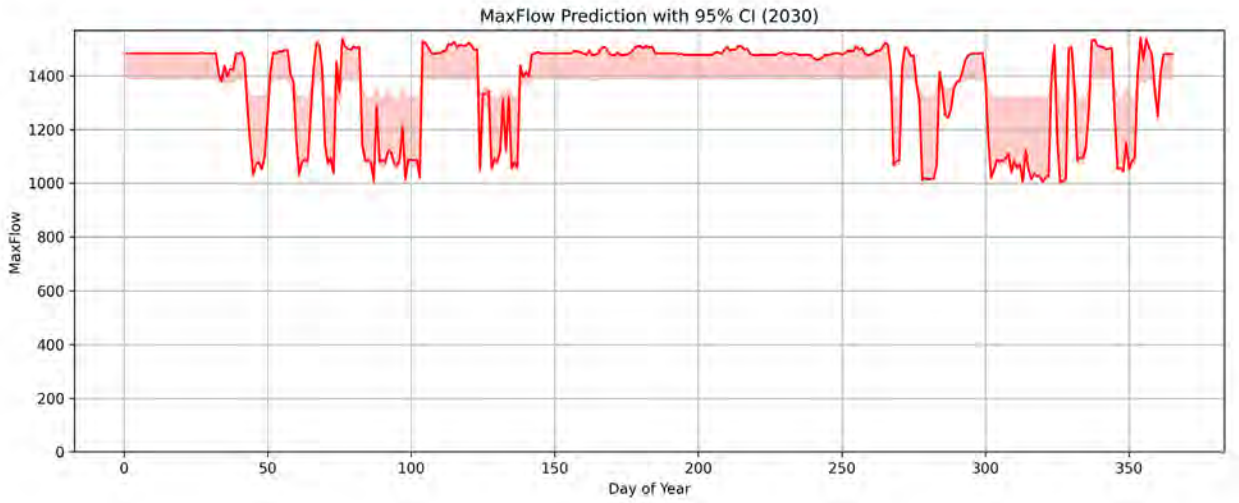


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

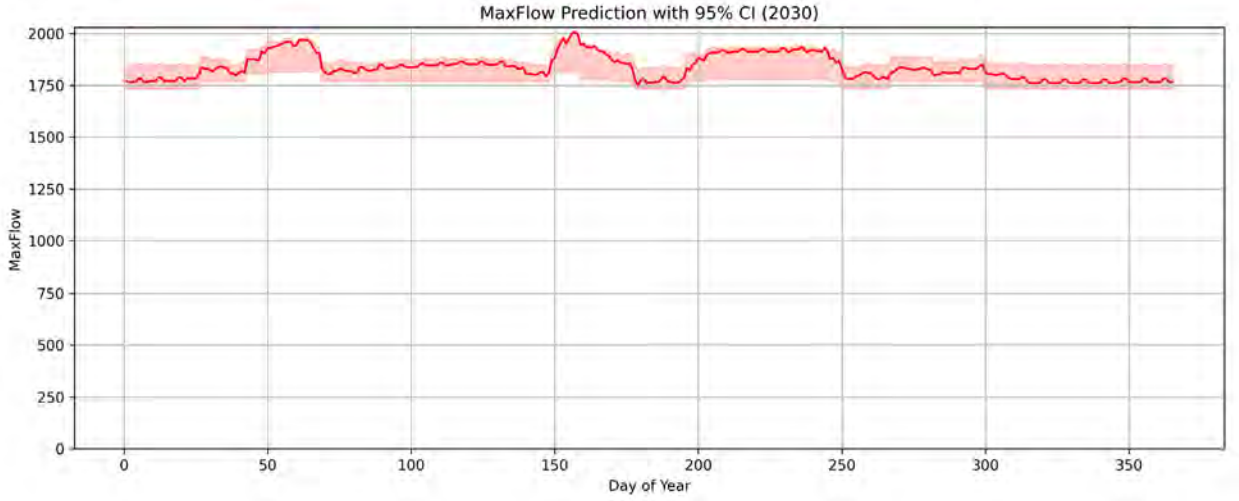


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

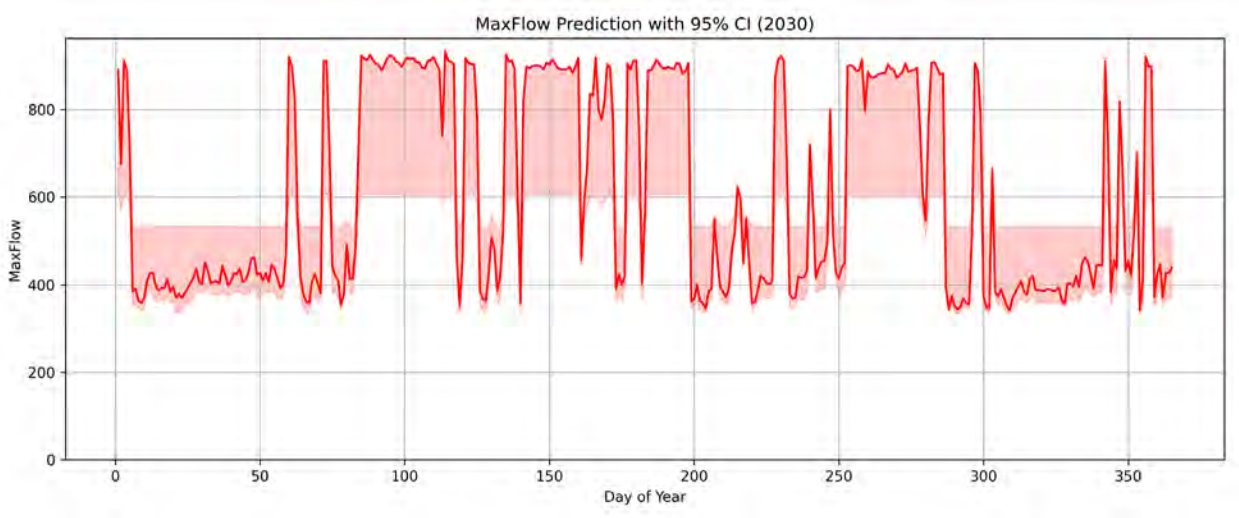


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

References

1. AESO. 2019. “Annual Market Statistics Report” https://public.tableau.com/app/profile/market.analytics/viz/AnnualStatistics_16161854228350/Introduction Last updated May 13, 2025.

2. AESO. “Hourly Metered Volumes and Pool Price and AIL” https://www.aeso.ca/assets/Uploads/data-requests/Hourly_Metered_Volumes_and_Pool_Price_and_AIL.csv Accessed May 30, 2025.

3. AESO. 2016 “Historical Generation Data (CSD)” https://www.aeso.ca/market/market-and-system-reporting/data-requests/historical-generation-data Accessed May 30, 2025.

4. BC Hydro. 2025. “Historical Transmission Data” https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/balancing-authority-load-data/historical-transmission-data.html

5. BPA. “Rolling 30 Days and Monthly History” https://transmission.bpa.gov/business/operations/paths/ Accessed May 30, 2025.

6. BPA. “VER* Generation and Total Load in The BPA Balancing Authority” https://transmission.bpa.gov/business/operations/wind/ Accessed May 30, 2025.

7. Government of Canada. 2022. “Historical Data on Electricity Consumption and Production in Quebec” https://open.canada.ca/data/en/dataset/bd6a1401-15db-438d-9b8b-ff11af48064e Updated July 24, 2024.

8. IESO. 2025. “Data Directory” https://www.ieso.ca/power-data/data-directory

9. IESO. 2019. “Yearly Intertie Actual Schedule and Flow Report” https://reports-public.ieso.ca/public/IntertieScheduleFlowYear/ Updated May 30, 2025.

10. IESO. 2018. ”Hourly Demand Report” https://reports-public.ieso.ca/public/Demand/ Updated May 30, 2025.

11. IESO. 2025. “Generator Output by Fuel Type Hourly Report” https://reports-public.ieso.ca/public/GenOutputbyFuelHourly/ Updated May 30, 2025.

12. ISO-NE. 2025. “Energy, Load, and Demand Reports: Zonal Information” https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

13. ISO-NE. 2025. “Energy, Load, and Demand Reports: Historical Hourly Flows and Limits” https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/historical-hourly-flows-and-limits

14. MISO. “Load, Generation, and Interchange API” https://data-exchange.misoenergy.org/api-details#api=load-generation-and-interchange-api&operation=get-v1-real-time-date-interchange-net-actual Accessed May 30, 2025.

15. NB Power. 2025. “System Information Archive” https://tso.nbpower.com/Public/en/system_information_archive.aspx Accessed May 30, 2025.

16. NYISO. 2002 “Internal and External Interface Limits and Flows” https://mis.nyiso.com/public/P-32list.htm Updated May 30, 2025.

17. NYISO. 2004 “Day-Ahead Markey Daily Energy Report" https://mis.nyiso.com/public/P-30list.htm Updated May 30, 2025

18. Stephen et al. 2022. “Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric” https://www.spp.org/documents/69303/lole%20metric.pdf

EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose*. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy*. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority*. (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

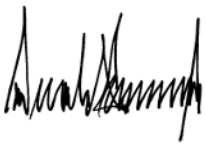
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid



U.S. DEPARTMENT of ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 97
DOE July 7 Press Release

An official website of the United States government Here's how you know

Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

Energy.gov

July 7, 2025

4 min

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

WASHINGTON— The U.S. Department of Energy (DOE) today released its Report on Evaluating U.S. Grid Reliability and Security. The report fulfills Section 3(b) of President Trump's Executive Order, *Strengthening The Reliability And Security Of The United States Electric Grid*, by

delivering a uniform methodology to identify at-risk regions and guide Federal reliability interventions.

The analysis reveals that existing generation retirements and delays in adding new firm capacity, driven by the radical green agenda of past administrations, will lead to a surge in power outages and a growing mismatch between electricity demand and supply, particularly from artificial intelligence (AI)-driven data center growth, threatening America's energy security.

"This report affirms what we already know: The United States cannot afford to continue down the unstable and dangerous path of energy subtraction previous leaders pursued, forcing the closure of baseload power sources like coal and natural gas," Secretary Wright said. "In the coming years, America's reindustrialization and the AI race will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power. President Trump's administration is committed to advancing a strategy of energy addition, and supporting all forms of energy that are affordable, reliable, and secure. If we are going to keep the lights on, win the AI race, and keep electricity prices from skyrocketing, the United States must unleash American energy."

Highlights of the Report:

- **The status quo is unsustainable.** DOE's analysis shows that, if current retirement schedules and incremental additions remain unchanged, most regions will face unacceptable reliability risks within five years and the Nation's electrical power grid will be unable to meet expected demand for AI, data centers, manufacturing and industrialization while keeping the cost of living low for all Americans. Staying on the present course would undermine U.S. economic growth, national security, and leadership in emerging technologies.

- **Grid growth must match the pace of AI innovation.** Electricity demand from AI-driven data centers and advanced manufacturing is rising at a record pace. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. Radical change is needed to unleash the transformative potential of innovation.
- **With projected load growth, retirements increase the risk of power outages by 100 times in 2030.** Allowing 104 GW of firm generation to retire by 2030—without timely replacement—could lead to significant outages when weather conditions do not accommodate wind and solar generation. Modeling shows annual outage hours could increase from single digits today to more than 800 hours per year. Such a surge would leave millions of households and businesses vulnerable. We must renew a focus on firm generation and continue to reverse radical green ideology in order to address this risk.
- **Planned supply falls short, reliability at risk.** The 104 GW of plant retirements are replaced by 209 GW of new generation by 2030; however, only 22 GW comes from firm baseload generation sources. Even assuming no retirements, the model found outage risk in several regions rises more than 30-fold, proving the queue alone cannot close the dependable-capacity deficit.
- **Old tools won't solve new problems.** Traditional peak-hour tests to evaluate resource adequacy do not sufficiently account for growing dependence on neighboring grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages, move beyond exclusively analyzing peak load time periods, and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

DOE's report identifies regions most vulnerable to outages under various weather and retirement scenarios and offers capacity targets needed to restore acceptable reliability. The methodology also informs the

potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.

Click here for a fact sheet on the report.

###

View Previous

Energy Department Issues Final Rule Delaying Compliance Deadline for Manufactured Housing Standards

July 1, 2025

View Next

Energy Department Expands Commitment to Collaboration with Norway on Water Power Research and Development

July 7, 2025

Tags:

STRENGTHEN GRID RELIABILITY AND SECURITY

Media Inquiries:
(202) 586-4940 or
DOENews@hq.doe.gov

Read more at the energy.gov Newsroom

U.S. DEPARTMENT of ENERGY

Committed to Restoring America's Energy Dominance.

Quick Links

Leadership & Offices
Mission
Newsroom
Contact Us
Careers

Resources

Budget & Performance
Directives, Delegations, & Requirements
Freedom of Information Act (FOIA)
Inspector General
Privacy Program

Federal Government

USA.gov
The White House

Follow Us

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 98
Culley East Ash Pond Closure Plan

AECOM

Submitted to
Southern Indiana
Gas & Electric Company
Inc. (SIGECO)
One Vectren Square
Evansville, IN 47708

Submitted by
AECOM
1300 East 9th Street
Suite 500
Cleveland, Ohio 44114

September 10, 2021

CCR Certification: Written Closure Plan §257.102 (b) & (d)

for the

East Ash Pond

at the

F.B. Culley Generating Station

Revision 1

Table of Contents

Executive Summary **1**
1 Introduction **1-1**
1.1 Purpose of this Report 1-1
1.2 Brief Description of Impoundment 1-1
2 Written Closure Plan **2-1**
2.1 Content of the Plan 2-1
2.1.1 Closure Plan Description 2-1
2.1.2 Inventory and Area Estimates 2-2
2.1.3 Closure Schedule 2-2
2.2 Achievement of Closure by Removal 2-3
2.3 Amendment to Initial or any Subsequent Written Closure Plan 2-3
3 Certification **3-1**
4 Limitations **4-1**

Tables

Table ES-1 Certification Summary
Table 1-1 CCR Rule Cross Reference Table
Table 2-1 Closure Schedule

Appendices

Appendix A Figures
Figure 1 – Location Map
Figure 2 – Site Map

Executive Summary

This Coal Combustion Residuals (CCR) Written Closure Plan (Closure Plan) for the East Ash Pond at the Southern Indiana Gas & Electric Company Inc., F.B. Culley Generating Station has been prepared in accordance with the requirements specified in the USEPA CCR Rule under 40 Code of Federal Regulations §257.102. These regulations require that the specified documentation, assessments and plans for an existing CCR surface impoundment be prepared by October 13, 2016. The Initial Closure Plan proposed a Closure-in-Place (CiP) methodology and was prepared in accordance with these requirements. This Closure Plan (Rev. 1) represents an update to the Initial Closure Plan (Rev. 0) considering recent developments to implement a closure by removal (CbR) methodology for closure of the East Ash Pond.

This Closure Plan meets the regulatory requirements as summarized in **Table ES-1.**

Table ES-1 – Certification Summary

Report Section	CCR Rule Reference	Requirement Summary	Requirement Met?	Comments
Closure Plan				
2.1	§257.102 (b)	*A written closure plan must be prepared that describes the steps necessary to close the unit*	Yes	This Closure Plan has been prepared based on a closure design. All steps necessary to close the unit and information as required concerning the unit are included in the Closure Plan.
2.2	§257.102 (c)	*Closure by Removal*	Yes	This Closure Plan has been prepared based on a closure by removal design. All steps necessary to close the unit and information as required concerning the unit are included in the Closure Plan.

The East Ash Pond at the F.B. Culley Generating Station is currently an active surface impoundment. Upon decision and/or requirement to close this surface impoundment, a Notification of Intent to Initiate Closure will be placed in the Operating Record, closure operations will commence, and the surface impoundment will be closed within the time frame as allowed in the CCR Rule. It is anticipated that the East Ash Pond will initiate closure by March 2023.

1 Introduction

1.1 Purpose of this Report

The purpose of the Closure Plan is to document that the requirements specified in 40 Code of Federal Regulations (CFR) §257.102 have been met to support the certification required under each of the applicable regulatory provisions for the East Ash Pond at F.B. Culley Generating Station. The East Ash Pond is an existing coal combustion residuals (CCR) surface impoundment as defined by 40 CFR §257.53. The CCR Rule requires that the Initial Written Closure Plan for an existing CCR surface impoundment be prepared by October 13, 2016. The Initial Closure Plan proposed a Closure-in-Place (CiP) methodology and was prepared in accordance with these requirements. This Closure Plan (Rev. 1) represents an update to the Initial Closure Plan (Rev. 0) considering recent developments to implement a closure by removal (CbR) methodology for closure of the East Ash Pond.

The following table summarizes the documentation required within the CCR Rule and the sections that specifically respond to those requirements of this plan.

Table 1-1 – CCR Rule Cross Reference Table

Report Section	Title	CCR Rule Reference
2.1	Content of the Plan	§257.102 (b)(1)
2.2	Achievement of Performance Standards	§257.102 (c)

1.2 Brief Description of Impoundment

The Culley station is located in Warrick County, Indiana, southeast of Newburgh, Indiana, and is owned and operated by Southern Indiana Gas and Electric Company (SIGECO). The Culley station (Culley) is located along the north bank of the Ohio River and the west bank of Little Pigeon Creek along the southeast portion of the site. Culley historically has had two CCR surface impoundments, identified as the West Ash Pond and the East Ash Pond. The East Ash Pond actively receives CCR materials and the West Ash Pond has since closed and no longer receives or manages CCR materials. This Closure Plan has been developed for the East Ash Pond. The East Ash Pond is approximately 10 acres in size.

The history of construction report for the East Ash Pond indicates that the pond construction commenced in the 1971. The original design plans indicate that earthen embankments for the East Ash Pond were constructed by placing fill along the south side (adjacent to the Ohio River) and the east side (adjacent to Little Pigeon Creek), and tying into existing high ground at the north and west sides. Prior to the construction of the generating station, Little Pigeon Creek originally ran through the footprint of the East Ash Pond, continuing through the current location of the generating station and the former West Ash Pond. During the construction of the generating station in the 1950s, Little Pigeon Creek was re-routed to the Ohio River east of the Culley Station. The top of the East Ash Pond embankment was constructed to an approximate elevation of 397 feet. Interior side slopes of the pond vary, but original design documents indicate that the slopes are approximately 2.5H:1V (horizontal to vertical) from the top

of the dike to approximately halfway down the interior slope until a flat bench. From the bench to the bottom of the pond, the slope is approximately 2H:1V. The embankment of the East Ash Pond is approximately 1,200 feet long, 15 feet wide at the crest, 30 feet high, and has approximately 2.5H:1V exterior side slopes covered with trees, riprap, concrete rubble and undergrowth vegetation. The surface area of the impoundment is approximately 9.8 acres. Within the pond, there are two small pools. One is being utilized as a settling basin for the discharge from the FGD wastewater treatment system. The ponded water has a surface area of approximately 7 acres and has a normal operating level of 386.5 feet.

A Site Location Map showing the area surrounding the station is included as **Figure 1** of **Appendix A**. **Figure 2** in **Appendix A** presents the F.B. Culley Site Map.

2 Written Closure Plan

Regulatory Citation: 40 CFR §257.102 (b); Written closure plan—

- *(1) Content of the plan. The owner or operator of a CCR unit must prepare a written closure plan that describes the steps necessary to close the CCR unit at any point during the active life of the CCR unit consistent with recognized and generally accepted good engineering practices. The written closure plan must include, at a minimum, the information specified in paragraphs (b)(1)(i) through (vi) of this section.*

The Written Closure Plan for the East Ash Pond is described in this section. Information about operational and maintenance procedures was provided by Culley plant personnel. The Culley station follows an established maintenance program that quickly identifies and resolves issues of concern.

2.1 Content of the Plan

2.1.1 Closure Plan Description

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(i) Narrative description of how the CCR unit will be closed in accordance with this section.*

The entire footprint of the East Ash Pond will be excavated to remove CCR to historical/pre-development grades. The East Ash Pond will be dewatered to facilitate CCR excavation. Excavated CCR materials will be either beneficially reused or disposed at a third party disposal site. The existing southern embankment will be breached to direct stormwater to an NPDES permitted outfall. Closure operations will involve:

1) Dewatering the impoundment;

2) Excavation and removal of all CCR materials;

3) Dike breach & outfall construction; and

4) Seeding and final vegetative stabilization

In accordance with §257.102(b)(3), this Closure Plan will be amended as needed to provide additional details after the final engineering design is completed. This Closure Plan reflects the information available to date.

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(ii) If closure of the CCR unit will be accomplished through removal of CCR from the CCR unit, a description of the procedures to remove the CCR and decontaminate the CCR unit in accordance with paragraph (c) of this section.*

Excavation in the East Ash Pond footprint will advance until historical/pre-development grades have been achieved and all CCR has been removed from within the CCR unit. Upon attaining pre-development grades, a visual inspection will be conducted to identify any remnant CCR materials. Remnant CCR materials identified by this inspection will subsequently be removed by additional excavation. This process may be supplemented by analytical testing to satisfy state-specific closure protocols, as appropriate. Following completion of this process and

consistent with current regulatory provisions, groundwater monitoring will be conducted until it can be confirmed that concentrations do not exceed the groundwater protection standard established pursuant to §257.95(h) for constituents listed in Appendix IV.

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(iii) If closure of the CCR Unit will be accomplished by leaving CCR in place, a description of the final cover system and methods and procedures used to install the final cover.*

Not applicable.

2.1.2 Inventory and Area Estimates

Regulatory Citation: 40 CFR §257.102 (b);

- *(iv) An estimate of the maximum inventory of CCR ever on-site over the active life of the CCR unit.*

An estimate of the maximum inventory of CCR ever on-site over the active life is 349,000 cubic yards.

Regulatory Citation: 40 CFR §257.102 (b);

- *(v) An estimate of the largest area of the CCR unit ever requiring a final cover as required by paragraph (d) of this section at any time during the CCR unit's active life.*

Not applicable.

2.1.3 Closure Schedule

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(vi) Schedule for completing all activities necessary to satisfy the closure criteria in this section, including an estimate of the year in which all closure activities for the CCR unit will be completed.*

The milestones and the associated timeframes are initial estimates. Some of the activities associated with the milestones will overlap. Amendments to the milestones and timeframes will be made as more information becomes available.

Table 2-1 – Closure Schedule

Milestone	Schedule
Initial Written Closure Plan (Rev. 0)	October 13, 2016
Written Closure Plan (Rev. 1)	September 10, 2021
Notification of Intent to Close Placed in Operating Record	March 2023 or no later than the date closure of the CCR unit is initiated. Closure to commence in accordance with the applicable timeframes in 40 CFR 257.102(e).

Table 2-1 – Closure Schedule	
Milestone	Schedule
Agency coordination and permit acquisition – Coordinating with state agencies for compliance. – Acquiring state permits.	2021-2023 2022-2023
Mobilization	March 2023
Closure Construction Activities CCR – Complete dewatering, as necessary – Complete excavation of CCR – Final Dike Breach/Final Stabilization	 June 2024 June 2024 December 2024
Estimate of Year in which all closure activities will be completed.	2024-2025

2.2 Achievement of Closure by Removal

Regulatory Citation: 40 CFR §257.102 (c); Closure by removal of CCR

An owner or operator may elect to close a CCR unit by removing and decontaminating all areas affected by releases from the CCR unit. CCR removal and decontamination of the CCR unit are complete when constituent concentrations throughout the CCR unit and any areas affected by releases from the CCR unit have been removed and groundwater monitoring concentrations do not exceed the groundwater protection standard established pursuant to §257.95(h) for constituents listed in appendix IV to this part.

Excavation in the East Ash Pond footprint will advance until historical/pre-development grades have been achieved and all CCR has been removed from within the CCR unit. Upon attaining pre-development grades, a visual inspection will be conducted to identify any remnant CCR materials. Remnant CCR materials identified by this inspection will subsequently be removed by additional excavation. This process may be supplemented by analytical testing to satisfy state-specific closure protocols, as appropriate. Following completion of this process and consistent with current regulatory provisions, groundwater monitoring will be conducted until it can be confirmed that concentrations do not exceed the groundwater protection standard established pursuant to §257.95(h) for constituents listed in Appendix IV.

2.3 Amendment to Initial or any Subsequent Written Closure Plan

The Initial Written Closure Plan (Rev. 0) dated October 13, 2016 is hereby being amended by this Written Closure Plan (Rev. 1) on September 10, 2021 as required by §257.102 (b)(3).

3 Certification

This Certification Statement documents that the East Ash Pond at the F.B. Culley Generating Station meets the Written Closure Plan requirements specified in 40 CFR §257.102 (b) and the closure by removal requirements as specified in 40 CFR §257.102 (c). The East Ash Pond is an existing CCR surface impoundment as defined by 40 CFR §257.53. The CCR Rule requires that the Initial Written Closure Plan for an existing CCR surface impoundment be prepared by October 13, 2016. An amendment to the Initial Written Closure Plan is provided herein, dated September 10, 2021.

CCR Unit: Southern Indiana Gas & Electric Company; F.B. Culley Generating Station; East Ash Pond

I, Jay Mokotoff, being a Registered Professional Engineer in good standing in the State of Indiana, do hereby certify, to the best of my knowledge, information, and belief that the information contained in this certification has been prepared in accordance with the accepted practice of engineering. I certify, for the above referenced CCR Unit, that the Initial Written Closure Plan dated October 13, 2016 and hereby amended on September 10, 2021 meets the requirements of 40 CFR § 257.102.

Jay D. Mokotoff
Printed Name

September 10, 2021
Date



4 Limitations

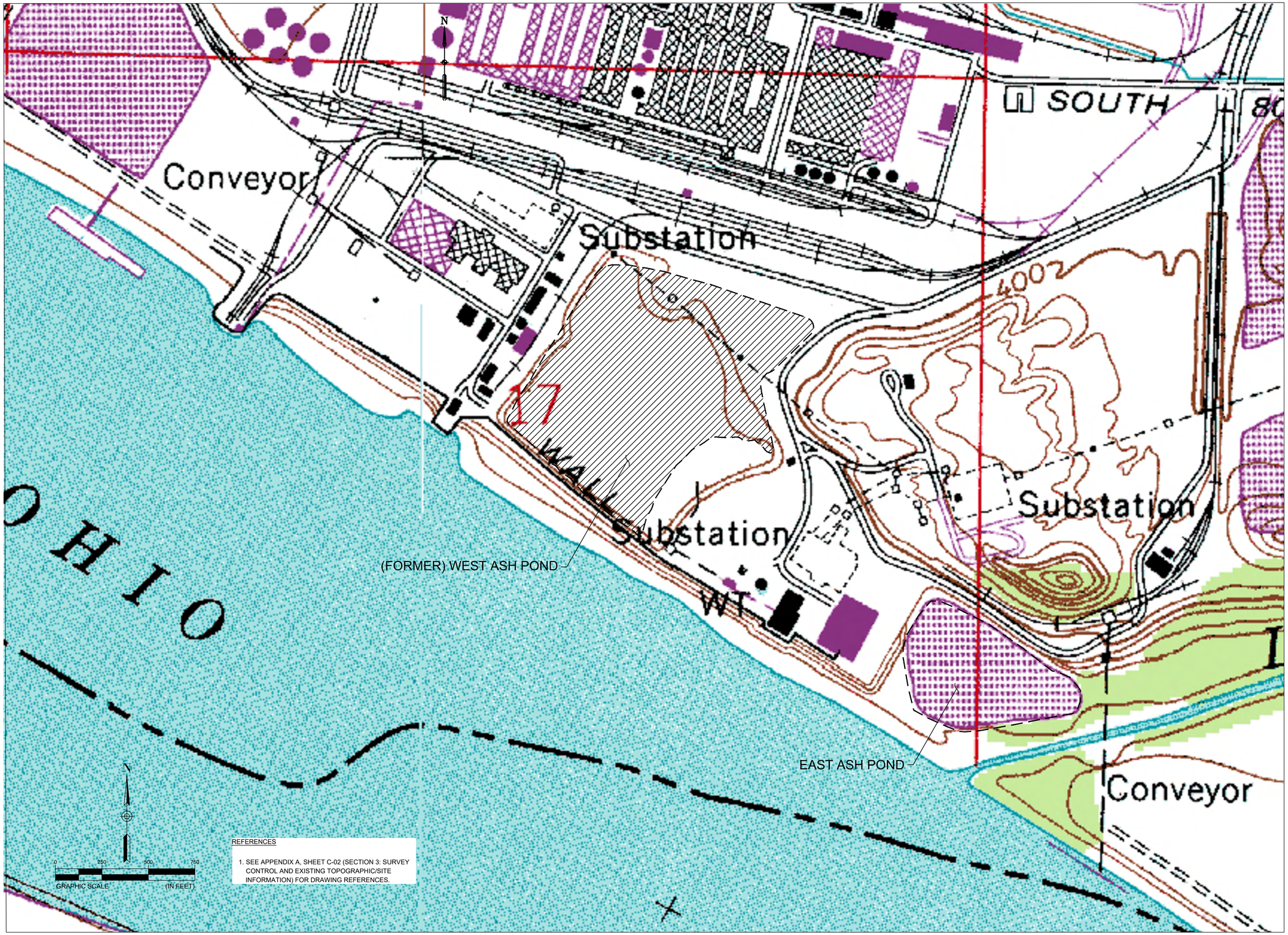
Background information, design basis, and other data which AECOM has used in preparing this report have been furnished to AECOM by SIGECO. AECOM has relied on this information as furnished and is not responsible for the accuracy of this information. Our recommendations are based on available information from previous and current investigations. These recommendations may be updated as future investigations are performed.

The conclusions presented in this report are intended only for the purpose, site location, and project indicated. The provisions and recommendations presented in this report should not be used for other projects or purposes. Conclusions or recommendations made from these data by others are their responsibility. The conclusions and recommendations are based on AECOM's understanding of current plant operations, maintenance, stormwater handling, and ash handling procedures at the station, as provided by SIGECO. Changes in any of these operations or procedures may invalidate the findings in this report until AECOM has had the opportunity to review the findings and revise the report if necessary.

This development of the Closure Plan was performed in accordance with the standard of care commonly used as state-of-practice in our profession. Specifically, our services have been performed in accordance with accepted principles and practices of the engineering profession. The conclusions presented in this report are professional opinions based on the indicated project criteria and data available at the time this report was prepared. Our services were provided in a manner consistent with the level of care and skill ordinarily exercised by other professional consultants under similar circumstances. No other representation is intended.

Appendix A
Figures

Figure 1 – Location Map
Figure 2 – Site Map



REFERENCES

1. SEE APPENDIX A, SHEET C-02 (SECTION 3: SURVEY CONTROL AND EXISTING TOPOGRAPHIC/SITE INFORMATION) FOR DRAWING REFERENCES.

AECOM
1300 E 9th St.
Suite 500
Cleveland, Oh 44114
216 622-2300 (phone)
216 622-2464 (fax)

CenterPoint Energy
P.O.BOX 209
EVANSVILLE, IN 47702
1-800-227-1376

F.B. CULLEY
GENERATING STATION
NEWBURGH, INDIANA

CLOSURE BY REMOVAL
OF EAST ASH POND

CLOSURE PLAN

NOT FOR
CONSTRUCTION

ISSUED FOR BIDDING ____ DATE BY

ISSUED FOR CONSTRUCTION ____ DATE BY

REVISIONS

NO.	DESCRIPTION	DATE
△		
△		
△		
△		
△		

AECOM PROJECT NO:	60586569
DRAWN BY:	WCPP
DESIGNED BY:	AG
CHECKED BY:	JDM
DATE CREATED:	
PLOT DATE:	07/29/2021
SCALE:	NOTED
ACAD VER:	2019

SHEET TITLE

SITE LOCATION

FIGURE 1

SHEET 1 OF 2

AECOM DRAWING PATH: C:\Users\Wadson.Phanord\Desktop\Culley East\DEM Version\Appendices\Figures\Figure 1 – Site Location.dwg
PHANORD, PIERRE, WADSON, C, 8/2/2021, 2:14 PM

AECOM
1300 E 9th St.
Suite 500
Cleveland, Oh 44114
216 622-2300 (phone)
216 622-2464 (fax)

CenterPoint Energy
P.O.BOX 209
EVANSVILLE, IN 47702
1-800-227-1376

F.B. CULLEY
GENERATING STATION
NEWBURGH, INDIANA

CLOSURE BY REMOVAL
OF EAST ASH POND

CLOSURE PLAN

NOT FOR
CONSTRUCTION

ISSUED FOR BIDDING	DATE BY
ISSUED FOR CONSTRUCTION	DATE BY

REVISIONS

NO.	DESCRIPTION	DATE
△		
△		
△		
△		
△		

AECOM PROJECT NO:	60586569
DRAWN BY:	WCPP
DESIGNED BY:	AG
CHECKED BY:	JDM
DATE CREATED:	
PLOT DATE:	07/29/2021
SCALE:	NOTED
ACAD VER:	2019

SHEET TITLE

AERIAL SITE MAP

FIGURE 2

SHEET 2 OF 2

AECOM DRAWING PATH: C:\Users\Wadson.Phanord\Desktop\Culley East\IDEM Version\Appendices\Figures\Figure 2 - Site Aerial.dwg

PHANORD PIERRE, WADSON C, 8/2/2021 2:20 PM

About AECOM

AECOM (NYSE: ACM) is a global provider of professional technical and management support services to a broad range of markets, including transportation, facilities, environmental, energy, water and government. With nearly 100,000 employees around the world, AECOM is a leader in all of the key markets that it serves. AECOM provides a blend of global reach, local knowledge, innovation, and collaborative technical excellence in delivering solutions that enhance and sustain the world's built, natural, and social environments. A Fortune 500 company, AECOM serves clients in more than 100 countries and has annual revenue in excess of $19 billion.

AECOM
9400 Amberglen Boulevard
Austin, Texas 78729
1-512-454-4797

About AECOM

AECOM (NYSE: ACM) is a global provider of professional technical and management support services to a broad range of markets, including transportation, facilities, environmental, energy, water and government. With nearly 100,000 employees around the world, AECOM is a leader in all of the key markets that it serves. AECOM provides a blend of global reach, local knowledge, innovation, and collaborative technical excellence in delivering solutions that enhance and sustain the world's built, natural, and social environments. A Fortune 500 company, AECOM serves clients in more than 100 countries and has annual revenue in excess of $19 billion.

More information on AECOM and its services can be found at www.aecom.com.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 99
RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

In re	)
Resource Adequacy Report	)
Evaluating the Reliability and Security	)
Of the United States Electric Grid	)
	)

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar

I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar ("Public Interest Organizations") hereby move, to the extent necessary, to intervene and request rehearing of the Department of Energy's ("Department" or "DOE") "Resource Adequacy Report: Evaluating the Reliability and Security of the United States" ("RAR").[1] The Department issued the RAR in response to Executive Order 14,262 *Strengthening the Reliability and Security of the United States Electric Grid,* April 8, 2025 ("Grid EO"),[2] and claims that the RAR is a "uniform methodology to identify at-risk region(s) and guide reliability interventions" as directed by the Grid EO.[3] But the Department simultaneously disclaims the utility of the RAR to guide interventions uniformly, acknowledging on the very first page that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in their parts of the grid.[4]

The flaws in the RAR continue. The Department overstates assumptions about demand growth and likely retirements while understating likely new entry, building into the RAR an inherent bias toward a finding of inadequate resource adequacy. The Department also departs from best practices by using a

[1] July 7, 2025, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf (attached as Ex. 1) (hereinafter, the "RAR").

[2] 90 Fed. Reg. 15521 (Apr. 8, 2025) (hereinafter "Grid EO").

[3] *Id.* at vi.

[4] *Id.* at i.

deterministic approach, which fails to account for necessary uncertainties and demonstrates that the RAR's findings should not be taken as conclusive or form the basis for further extraordinary actions. And on some critical aspects of the RAR analysis, the Department simply fails to explain its own methodology; while the Department describes two thresholds at which the RAR projects outages will occur, it fails to explain when it applies the standard threshold and when it applies the elevated one. These flaws render any reliance on the RAR to "guide reliability interventions" arbitrary and capricious.

While the Department acknowledges that the RAR is unsuitable to guide reliability interventions uniformly and provided no notice or opportunity to comment, the Department nevertheless does not clarify how it will use the RAR, creating confusion as to whether the RAR, in conjunction with the Grid EO, is intended to function as a final rule. Public Interest Organizations believe that the RAR should not be used as the basis for future action by the Department. We submit this request for rehearing in an abundance of caution, to the extent the Department later argues that any of these issues must have been raised in a request for rehearing within 30 days of the publication of the RAR, 16 U.S.C. § 825*l*. We also reserve our right to argue in later proceedings that 16 U.S.C. § 825*l* does not apply.

In sum, the RAR is a poorly crafted solution in search of a problem; there is no "energy emergency" and the regulatory bodies who actually possess authority to ensure resource adequacy are doing their jobs. Consequently, the RAR serves no useful purpose and should simply be withdrawn. By DOE's own admission, the RAR cannot reasonably be relied on to guide DOE interventions, nor, given the false premise and multiple mistaken assumptions, does it provide any value even as a purely informational report. On the contrary, it will only cause confusion for grid operators, energy providers, and members of the public. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

II. STATEMENT OF ISSUES

1. The Department intrudes on Federal Energy Regulatory Commission ("FERC" or "the Commission") and state authority. 16 U.S.C. §§ 824a(c),824o-1; 42 U.S.C. § 7113.
2. The RAR's findings, even if accurate, do not demonstrate any emergency allowing the Department to compel generation under the Federal Power Act. 16 U.S.C. § 824a(c); S. Rep. No. 74-621 (1935); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,985.

3. The RAR is analytically flawed and does not rely upon substantial evidence. 16 U.S.C. 824a(a); 16 U.S.C. § 824o(a)(3).
4. The Department cannot use the RAR as a "uniform methodology" without giving notice and taking public comment. 5 U.S.C. §§ 552, 553; 10 C.F.R. §§ 205.371; 205.373.
5. The Department cannot use the RAR as a "uniform methodology" without following National Environmental Policy Act procedural requirements. 42 U.S.C. § 4332(C).

III. INTERVENTION

Each of the Public Interest Organizations has interests that may be directly and substantially affected by the use of this RAR as a "uniform methodology" to guide "reliability interventions," including the issuance of Emergency Orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c).[5] To the extent that the RAR is determined to be an Order or Rule, each party may intervene in this proceeding.[6] And to the extent the Department treats the RAR as binding and uses it to guide reliability interventions, each of the Public Interest Organizations and their members will suffer concrete injuries that are redressable through rehearing.[7] Each organization is therefore aggrieved if the RAR is a "uniform methodology" for use in guiding interventions, as the Department purports, and each organization may properly apply for rehearing, assuming without conceding that the rehearing procedures apply.[8]

A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants. NRDC works to achieve clean

---

[5] *See* RAR, Ex. 1 at iv.

[6] *See* U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (archived version attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 30, 2005) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.") (attached as Ex. 3).

[7] *See, e.g. Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009).

[8] *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has hundreds of thousands of members across the United States. These NRDC members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual impacts of these facilities' operations. In addition, NRDC members are ratepayers in regions who will be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. For that reason, NRDC filed requests for rehearing of DOE's 202(c) orders issued to the J.H. Campbell and Eddystone plants, the latter of which explicitly stated that it would be reexamined following publication of the methodology. NRDC has five U.S. offices that also will be subject to higher electric bills as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. The Ecology Center

The Ecology Center is a Michigan-based non-profit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean energy production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6,000 members and supporters, that live, use electricity, and pay electric bills in Michigan and could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. In addition, Ecology Center members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject Ecology Center members to air and water pollution in the areas where they live, work, and recreate.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a non-profit membership organization with hundreds of thousands of members nationwide whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across

the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Recent 202(c) Orders issued by the DOE have harmed members of EDF by causing increases in pollution, which impact the health of people and nature, and in energy costs. EDF has submitted requests for rehearing regarding the DOE Orders related to the J.H. Campbell and Eddystone power plants and a Petition for Review regarding the DOE Order regarding the J.H. Campbell plant. Further 202(c) Orders issued as a result of the RAR, including extensions of the J.H. Campbell and Eddystone orders and orders directed at other generators, will result in further pollution and cost impacts that will harm EDF members.

D. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest. Among other things, ELPC advocates before state public service commissions and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC members in the Midwest live, work, and recreate near power plants that burn coal or other fossil fuels and are directly impacted by their pollutants. In addition, ELPC members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. ELPC and its members could be subject to higher electric bills and impacted by additional pollution as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." ELPC has a longstanding organizational commitment to protect the interests of its members, to reduce pollution caused by fossil fuel-fired power plants, and to promote clean, reliable energy generation.

E. Public Citizen

Public Citizen, Inc. hereby intervenes in these proceedings. Public Citizen, Inc. is an active intervenor and participant before the Federal Energy Regulatory Commission in Federal Power Act proceedings, as well as before the U.S. Department of Energy in both electricity export and natural gas export dockets to ensure just and reasonable rates and that utilities' operations are consistent with the public interest. Established in 1971, Public Citizen, Inc. is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of American household consumers. Public Citizen has members in all 50 states and represents the interests of consumers, not represented by any other party in this proceeding. Financial details about our organization are on our website: www.citizen.org/about/annual-report/.

F. Sierra Club

Sierra Club is a national environmental non-profit whose purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. To those ends, the Sierra Club and its members have worked to limit pollution caused by fossil-fuel-fired power plants through public education and advocacy at the local, state, and federal level. Sierra Club represents over 640,000 members nationwide, many of whom reside and recreate in the regions in which the RAR purports to identify resource shortfalls requiring the continued operation of coal- and gas-fired generation. Sierra Club members in those areas would be harmed by the pollution and the increased utility rates caused by any such continued operation.

G. Vote Solar

Vote Solar is an independent 501(c)(3) non-profit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

IV. BACKGROUND

A. Executive Orders

The genesis of the RAR lies in the President's unsupported day one declaration of a national energy emergency: *Declaring a National Energy Emergency* ("Energy Emergency EO").[9] That declaration's lack of factual underpinning was highlighted in a recent report by DOE's independent statistics and analysis arm, the Energy Information Administration ("EIA"). The EIA report highlights how U.S. energy production and exports are currently at an all-time high.[10] Nonetheless, the Energy Emergency EO was cited as a basis for the

[9] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (January 20, 2025) (hereinafter "Energy Emergency EO") (attached as Ex. 4). *See* also RAR, Ex. 1 at vi (explaining that the Grid EO "builds on" the Energy Emergency EO).

[10] *See* U.S. EIA, *U.S. primary energy production, consumption, and exports increased in 2024* (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

President's follow-up grid-specific executive order, the Grid EO, that led to DOE's publication of the RAR.[11]

The Grid EO directed DOE to take three steps to address the President's assertion that there may be lack of grid reliability in the future, including: 1) to streamline the processes to issue orders pursuant to Federal Power Act Section 202(c);[12] 2) to develop a reserve margin assessment methodology and use it to identify at risk regions and critical energy resources within those regions and to publish that methodology within 90-days of the Grid EO;[13] and 3) to establish a protocol for identifying critical generating resources and taking action to prevent retirement or conversion of the fuel source of such resources.[14]

Notably, the Grid EO was issued in conjunction with a series of actions by President Trump and DOE designed explicitly to prop up the coal and gas industries, including: 1) Executive Order 14,261, *Reinvigorating America's Beautiful Clean Coal Industry,*[15] which seeks to restart coal leasing and expand coal mining on federal lands, in addition to making these processes easier by offering loans and streamlining permitting;[16] 2) a Presidential Proclamation entitled *Regulatory Relief for Certain Stationary Sources to Promote American Energy* that exempts coal plants from complying with the U.S. Environmental Protection Agency's updated Mercury and Air Toxics Standards;[17] and 3) Executive Order 14,260, *Protecting American Energy from State Overreach*,[18] which directs the U.S.

---

[11] Nor does the Energy Emergency EO supply legal support for the Grid EO. Under the National Emergencies Act, 50 U.S.C. § 1631, a declaration of national emergency does not authorize the exercise of emergency powers "unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." But as Congress made clear, the statute "is not intended to enlarge or add to Executive power" such as authority under Section 202(c), only to "establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976).

[12] Grid EO Section 3(a).

[13] *Id.* Section 3(b).

[14] *Id.* Section 3(c).

[15] *See* Exec. Order No. 14,261, 90 Fed. Reg. 15,517 (Apr. 8, 2025).

[16] DOE simultaneously announced several initiatives to subsidize the coal industry, including loan guarantees for coal-fired power plant projects. Dep't of Energy, *Energy Department Acts to Unleash American Coal by Strengthening Coal Technology and Securing Critical Supply Chains* (Apr. 8, 2025), https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing.

[17] Proclamation No. 10914, 90 Fed. Reg. 16777 (Apr. 8, 2025).

[18] Exec. Order No. 14,260, 90 Fed. Reg. 15513 (Apr. 8, 2025).

Department of Justice to take action to block states' exercises of their police powers to protect their residents from pollution caused by coal and fossil-fuel sources.[19]

B. RAR

On July 7, 2025, DOE published the RAR on its website. The RAR includes a deterministic analysis of the resource adequacy of the current electric system and three 2030 cases: (1) the Plant Closure case includes 104 GW of coal and gas retirements plus 100% of NERC's Tier 1 additions; (2) the No Plant Closures case includes no retirements but 100% of NERC's Tier 1 additions; and (3) the Required Build case begins with the Plant Closures scenario and projects what additional added perfect capacity would be needed to meet the RAR's determined reliability standards.[20] Each of the three 2030 scenarios assume 50 GW of load growth from data centers and an additional 51 GW of load growth from other sources.[21] The Department finds in the RAR that, under the current system, only ERCOT fails to achieve DOE's selected resource adequacy targets,[22] but that, based on the methodology used to forecast the 2030 scenarios, there will be broader resource adequacy issues in 2030.[23] And, notwithstanding the RAR's upfront acknowledgement that the analysis used "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level,"[24] the Department proceeds to make broad declarations of future need based on its findings in the RAR.[25]

DOE explained that the RAR was being issued pursuant to the Grid EO. The RAR incorporates a full copy of the Grid EO and explains that "[t]his report serves as DOE's response to [the Grid EO's] Section 3(b) … by delivering the required uniform methodology to identify at-risk region(s) and guide reliability

---

[19] These actions mimic President Trump's failed efforts to prop up the coal industry during his first term, including DOE's proposed rule, soundly rejected by FERC, that would have provided assured cost recovery (including a return on equity) for coal and nuclear plants (*see* 162 FERC ¶ 61,012), and the President's unfulfilled directive that DOE use Section 202(c) and the Defense Production Act to block closure of uneconomic coal plants while requiring grid operators to bear the costs. *See* Draft Memorandum (May 29, 2018), https://embed.documentcloud.org/documents/4491203-Grid-Memo/.

[20] RAR, Ex. 1 at 4-5.

[21] *Id.* at 2-3, 15-17.

[22] *Id.* at 7.

[23] *Id.* at 6-9.

[24] *Id.* at i.

[25] *Id.* at 1-2. *See also*, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security.

interventions."[26] DOE's statement that it intends to use the methodology "to guide reliability interventions" and that DOE will continue to use the RAR "on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States" suggests that the RAR may be intended to also serve as the protocol called for by Section 3(c) of the Grid EO.[27] But the RAR fails to clarify this, or, if the RAR does not also serve as DOE's response to Section 3(c), whether a protocol has been or will be developed, or whether any protocol will be made public. The RAR does not include any discussion of Section 3(a) of the Grid EO. To the extent that the Department addressed that portion of the Grid EO's directions, it has not made any process changes public. On the contrary, the Department has made its processes under Section 202(c) even less transparent by removing the existing process guidance from the DOE website.[28]

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[30]

C. Section 202(c) Orders

Section 202(c) of the Federal Power Act allows the Secretary of Energy, in certain emergency situations, to require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary

---

[26] RAR, Ex. 1 at vi.

[27] *Id.*

[28] *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website.

[29] *See* Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

determines will best meet the emergency and serve the public interest. Section 202(c) has an important purpose: to mitigate electricity shortages caused by war, drought, and other emergencies. In granting DOE the authority that Section 202(c) provides, Congress considered the severe societal consequences of blackouts and determined that avoiding those consequences justified allowing DOE to act without notice and to require operations that override environmental laws. But Congress was also very careful to narrowly limit DOE's use of that authority, as the title of the provision makes clear, to "temporary" "emergency" situations.[31] And while the statute doesn't define "emergency," DOE's regulations include a lengthy definition which reinforces the key element in the statute: 202(c) orders are for situations that are sudden and unexpected, not for longer term grid management.[32]

1. DOE's Past Use of 202(c) Orders

The Department's application of Section 202(c) consistently confirms the urgency of the conditions necessary to invoke the provision and underscores the lack of authority for the planned implementation scheme described in the Grid EO and RAR.[33] The Department's predominant practice has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[34]

---

[31] *See, e.g., Richmond Power & Light,* 574 F.2d at 617 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor.").

[32] 10 C.F.R. § 205.371: "'Emergency,' as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[33] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[34] *See, e.g.,* Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and

The law also requires the Department to narrowly tailor the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, limit the order to "only [the] hours necessary to meet the emergency," be "consistent with any applicable Federal, State, or local environmental law or regulation," and to "minimize[] any adverse environmental impacts.[35] Up until recently, the Department has routinely followed these provisions of the law.[36]

2. DOE's Recent Misuse of Section 202(c)

Prior to issuance of the RAR but consistent with the direction in the Grid EO, DOE issued two Section 202(c) orders blocking the planned closures of two fossil-fuel fired generation resources that were unreliable, uneconomic, and at the end of their useful lives: the J.H. Campbell coal-fired plant in West Olive Michigan,[37] and units 3 and 4 of the Eddystone oil and gas fired plant in Eddystone, Pennsylvania.[38] The Eddystone 202(c) Order stated that "DOE plans to use this methodology [i.e., the RAR] to further evaluate Eddystone Units 3 and 4," thus raising questions about DOE's intentions as to the legal status and efficacy of the RAR.

Public Interest Organizations filed requests for rehearing for both the J.H. Campbell and Eddystone 202(c) Orders.[39] In both cases DOE failed to identify conditions that would qualify as "emergencies" for the purpose of issuance of Section 202(c) Orders. And both Section 202(c) Orders impose significant costs on ratepayers,[40] while increasing emissions of air pollutants and providing no

---

December 26) (attached as Ex.5); Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires) (attached as Ex.6); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century) (attached as Ex. 7).

[35] 16 U.S.C.§ 824a(c)(2).

[36] *See, e.g.,* Ex.5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex.6, Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

[37]Dep't of Energy Order No. 202-25-3 (May 23, 2025) (attached as Ex. 8).

[38]Dep't of Energy Order No. 202-25-4 (May 30, 2025) (hereinafter "Eddystone 202(c) Order") (attached as Ex. 9).

[39] Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-3 (June 18, 2025) (hereinafter "Campbell RFR") (attached as Ex.10);Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-4 (June 27, 2025) (hereinafter "Eddystone RFR") (attached as Ex.11).

meaningful corresponding reliability benefit.[41] The Department denied both of Public Interest Organization's requests for rehearing by operation of law.[42]

D. Existing Mechanisms Ensure Resource Adequacy

In the United States, how electricity is bought and sold varies by region. Electric utilities can be either traditionally regulated and operate as vertically integrated monopolies, or they can operate in deregulated, competitive markets where electric energy prices are set by the market. Both vertically integrated utilities and utilities in deregulated markets are subject to federal oversight, and in some of the deregulated states, the state nonetheless exercises oversight over the terms of retail supply offers, especially for retail customers. And all utilities are subject to reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by FERC. In sum, FERC, Regional Transmission Organizations ("RTOs"), States, and NERC all play a hand in ensuring resource adequacy.

1. Vertically integrated utilities

Until the 1990s, utilities were generally vertically integrated such that generation, transmission, and distribution resources were all held by the same entity.[43] Vertically integrated utilities must seek state approval for power plant investments.[44] Many state regulators require utilities to demonstrate the necessity of proposed investments through an integrated resource planning process.[45] This process is used for long-term planning and requires the utility to justify its investments and demonstrate how it plans to meet customer electricity demand.[46] Even though vertically integrated utilities generate their own electricity, many

---

[40] *See e.g.* U.S. Sec. and Exch. Comm'n, Form 10-Q, Consumers Energy Company Quarterly Report For the Quarterly Period Ended June 30, 2025, at 39, 62, 92 (2025) https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf (describing costs of $29 million to operate Campbell through June 30, 2025); FERC Docket No. ER25-2653-000 (PJM proposed cost allocation to implement DOE Order 202-25-4).

[41] *See* Campbell RFR, Ex. 10 at 11-14; Eddystone RFR, Ex. 11 at 56-60. 87-88.

[42] Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-3A (July 28, 2025) (attached as Ex. 12); Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-4A (Aug. 1, 2025) (attached as Ex. 13).

[43] *See* Kathryne Cleary and Karen Palmer, *US Electricity Markets 101* (March 17, 2022), Resources for the Future, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

[44] *Id.*

[45] *Id.*

[46] *Id.*

trade with other utilities during times of need. These wholesale market transactions are subject to regulation by FERC.[47]

2. Competitive markets

Advances in technology and statutory changes led to the development of energy markets and merchant generation that is not owned by incumbent utilities.[48] In the 1990s, FERC fostered competitive markets through rules that allowed the establishment of independently-operated voluntary RTOs that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources through Order Nos. 888, 890, and 2000.[49] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Deregulated states use markets to determine which power plants are necessary for electricity generation.[50] Even in deregulated states, the state sites new generation. Market price signals encourage new investment when supply is tight and encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[51]

---

[47] *See* FERC, *Electric Power Markets* (last updated March 27, 2025), https://www.ferc.gov/electric-power-markets.

[48] *See, e.g.,* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012, PP 7-11 (2018); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

[49] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[50] State regulators in competitive markets still practice oversight over utilities. For example, some states, such as Michigan, use both the market and integrated resource planning. *See* Michigan Public Service Commission, *Phase III – Integrated Resource Plan* (last visited Aug. 4, 2025), https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red. Other state legislatures or commissions have enacted subsidies to keep nuclear plants alive, such as in New York, Illinois, Ohio, and New Jersey. *See* U.S. EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[51] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019) https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[52] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[53]

3. FERC and NERC Reliability Regulation

As part of its role in regulating the wholesale electric industry, FERC has implemented Congressional mandates to ensure system reliability, including establishing NERC as the Electric Reliability Organization, which sets industry standards for grid reliability that are approved by FERC;[54] coordination requirements for the natural gas and electricity market scheduling;[55] investigation and improvements required in light of the grid's response to extreme weather events;[56] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[57]

---

customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[52] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[53] *Id.* (citation omitted).

[54] PJM, NERC and Reliability Fact Sheet (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf. *See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[55] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also* Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[56] *See e.g.,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024). *See also* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Entity Joint Staff, The February 2021 Cold Weather Outages in Texas and the

V. ARGUMENT

A. The Department Is Intruding on FERC and State Authority.

The Department's authority over reliability is strictly circumscribed to respond to imminent emergencies;[58] this authority does not extend to regulating long-term or overarching aspects of the electricity sector. Rather, Congress reserved to the states and FERC the authority to regulate the electric sector generally and to regulate resource adequacy and reliability specifically. Recent actions—starting with the Energy Emergency EO and culminating in the RAR—indicate, however, that DOE is not remaining in its designated lane.[59] The RAR lays bare the Department's agenda to prop up fossil fuel businesses by utilizing emergency authority in a systematic fashion that goes well beyond the scope of DOE's authority under the Federal Power Act and illegally intrudes upon authorities that Congress has explicitly reserved to the states or given to FERC.

The authority to maintain a reliable electric system in the United States has evolved over the years to include parties at the federal, regional, state, and local levels.[60] But the Department of Energy has never been granted primary regulatory authority over either reliability or resource adequacy of the grid. Rather, the Department of Energy Organization Act of 1977 ("Organization Act")[61] and the

---

South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[57] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

[58] *See* 16 U.S.C. §§ 824a(c),824o-1.

[59] *See* Energy Emergency EO, Ex. 4; Grid EO Sec. 3 (RAR, Ex. 1 at C); RAR Ex. 1; DOE, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security; Eddystone 202(c) Order, Ex. 9; Dep't of Energy Order No. 202-25-3 (May 23, 2025), Ex. 8.

[60] *New York v. FERC*, 535 U.S. 1, 5-8 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities"). *See generally* Nat'l Ass'n of Reg. Util. Comm'rs ("NARUC"), *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms* (Nov. 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3?_gl=1*oyp366*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzEkdDE3NTM5ODk1NzUkajI1JGwwJGgw; NARUC, *Resource Adequacy Primer for State Regulators* (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[61] 42 U.S.C. § 7111 *et seq.*

Federal Power Act[62] give to the Department only narrow, emergency authority over the electric system—for example through Federal Power Act Sections 202(c) and 215A.[63] The President's declaration of an energy emergency (even if it were legitimate) and other executive orders cannot expand these statutorily defined authorities.[64] And while the Department may of course analyze policy implications and issue reports on various topics—as it has done since its founding—DOE's statements indicate that the RAR is not simply a policy analysis. The Department states—without limitation—that it will use the RAR "to identify at-risk region(s) and guide reliability interventions."[65] Thus, taking DOE at its word, the RAR is beyond the Department's authority.

Further, to the extent that it is an indication of the Department's broader scheme, in the RAR, the Department ignores the limitations on its authority and the comparative breadth of authority explicitly reserved to the states and FERC over the Department. "States are responsible for resource adequacy in siting of electric facilities, establishing retail electric rates, and overseeing the reliability of the distribution system."[66] State public utility commissions review utility proposals for long-term impacts to the system's reliability. "Most states address resource adequacy by requiring large investor-owned utilities to file long-term planning documents like integrated resource plans that include strategies for reliably meeting future demand."[67]

The structure and language of the Organization Act and Federal Power Act reflect Congress's deliberate choices to preserve this traditional state authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. Congress noted in the Organization Act that "[n]othing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction."[68] And the first sentence of the Federal Power Act declares that

---

[62] Subsequent legislation has also amended and updated these authorities. *See e.g.* Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114–94, 129 Stat. 1312 (2015); Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 16 U.S.C. §§ 824a(c), 824o-1.

[64] *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023); *see also* S. Rep. No. 94-1168, 3 (1976), (the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.") (emphasis added).

[65] RAR, Ex. 1 at vi.

[66] NARUC, *Resource Adequacy Primer for State Regulators*, at 9 (July 2021) https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[67] Nat'l Renewable Energy Lab'y, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, at 4 (Jan. 2024) https://docs.nrel.gov/docs/fy24osti/85880.pdf.

[68] 42 U.S.C. § 7113.

federal regulation extends "only to those matters which are not subject to regulation by the States."[69] Section 201(b)(1) further states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy."[70] The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities,[71] including the authority to order their closure.[72] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[73] And when Congress added new authority regarding reliability to the Federal Power Act in 2005, it also still explicitly clarified that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard…."[74]

The RAR also intrudes upon authority that Congress explicitly and repeatedly gave exclusively to FERC, not the Department. In 1935, Congress passed the Federal Power Act, creating the Federal Power Commission to engage in "federal regulation of electricity in areas beyond the reach of state power."[75] However, until the 1970s, the federal government played a very limited role in energy policy and generally left to private industry and state and local governments the task of establishing energy policies and planning.[76] In 1977, Congress passed the Organization Act,[77] creating both the Department and FERC. The Organization Act transferred most of the authority for overseeing the electric system in the

---

[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

[71] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016).

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

[75] *New York v. FERC*, 535 U.S. 1, 6 (2002).

[76] DOE, *A Brief History of the Department of Energy,* https://www.energy.gov/lm/brief-history-department-energy. *See also* DOE, *Department of Energy 1977-1994, A Summary History* (Nov. 1994), https://www.energy.gov/sites/prod/files/2017/09/f36/DOE%201977-1994%20A%20Summary%20History_0.pdf.

[77] Public Law 95–91 (1977), 42 U.S.C. § 7101 *et seq.*

Federal Power Act to FERC, not the Department;[78] the Department retained primary authority only over "emergency interconnection."[79]

While FERC is housed within the Department, FERC is an independent agency with distinct authority from the Department that the Department may not modify or supersede.[80] Generally the Department "is authorized to establish, alter, consolidate or discontinue such organizational units or components within the Department as [the Secretary] may deem to be necessary or appropriate."[81] But this authority explicitly does not extend to FERC. The Organization Act explains that the Department may not abolish "organizational units or components established by" the Organization Act, nor may it "transfer [] functions vested by this chapter in any organizational unit or component."[82] Because the Organization Act created[83] and transferred specific authority to FERC,[84] the Department has no authority to alter FERC itself nor to seize FERC's statutorily prescribed authority.

Further, "the decision of the Commission involving any function within its jurisdiction . . . shall be final agency action . . . and *shall not be subject to further review by the Secretary* or any officer or employee of the Department."[85] While the Department can propose rules under FERC's jurisdiction, FERC maintains "exclusive jurisdiction . . . to take final action on any proposal made by the Secretary."[86] And when the Department proposes a rule in the exercise of its own functions that FERC determines significantly affects any function within FERC's jurisdiction, FERC can insist on changes that DOE must adopt if DOE wants to issue the rule.[87]

---

[78] 42 U.S.C. § 7172 (transferring functions from Federal Power Commission to FERC); 42 U.S.C. § 7151 (the function of the Federal Power Commission is transferred to the Secretary except as provided to FERC). The Department and FERC share authority over certain parts of the Federal Power Act that primarily address recordkeeping and administration. 42 U.S.C. § 7172(a)(2) ("The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission: (A) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act.").

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

[80] *See* 42 U.S.C.A. § 7112 (Congressional declaration of purpose in establishing Department); 42 U.S.C. § 7171 (establishment of FERC).

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

[83] 42 U.S.C. § 7171 (establishment of FERC).

[84] 42 U.S.C. § 7172(a) (transferring functions from Federal Power Commission to FERC).

[85] 42 U.S.C. § 7172(g) (emphasis added).

[86] 42 U.S.C. § 7173. *See* 162 FERC ¶ 61,012.

[87] 42 U.S.C. § 7174.

In 2005, Congress expanded FERC's authority to specifically encompass reliability by updating the Federal Power Act in the 2005 Energy Policy Act.[88] While "FERC had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[89] there had been no mandatory reliability standards adopted by any federal regulator. When providing recommendations on reliability in 1998, the Department had concluded "that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC."[90] The new Section 215 followed the Department's suggestion and "tasked FERC [—not the Department—] with a direct role over an entire new field of activity."[91] Section 215 authorizes FERC to certify an electric reliability organization; FERC designated NERC. It is therefore NERC that develops reliability standards that FERC reviews to ensure consistency with federal law.[92] The broad reliability authority Congress granted to FERC contrasts with the very narrow, emergency authority in Section 215A that Congress granted to the Department.[93] The RAR appears to duplicate FERC and NERC's reliability efforts, impermissibly intruding upon authority Congress chose to give FERC —subject to elaborate procedural and substantive limitations—not the Department.

---

[88] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[89] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[90] DOE, *Maintaining Reliability in a Competitive U.S. Electricity Industry* at vii-viii, xiv (Sept. 29, 1998), https://certs.lbl.gov/sites/all/files/basic-page/maintainting-reliability-in-competitive-electricity-industry-1998_0.pdf ("The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.") ("The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability."). *See also* S. Rep. No. 106-324, Electric Reliability 2000 Act (proposals from Congress such as this one gave FERC the authority over reliability).

[91] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[92] FERC, Reliability Explainer (Aug. 16, 2023) https://www.ferc.gov/reliability-explainer#:~:text=Both%20NERC%20and%20FERC%20have,blackouts%20or%20systematic%20compliance%20failures.

[93] The 2015 amendment to Federal Power Act creating Section 215A (16 U.S.C. 824o-1(d)) gives DOE the authority to issue orders to address emergencies related to malicious acts resulting from physical attacks to the grid at limited 15-day increments.

Finally, the Department arbitrarily and capriciously assumes that the existing systems are not working. The states and FERC have—pursuant to their authority—established systems to maintain resource adequacy and reliability including integrated resource planning processes and capacity markets. These existing systems are designed to signal to build more energy generation when energy demand rises.[94] Recently, as the Department notes in the RAR, energy demand has been rising; but the Department fails to acknowledge that the state and FERC systems already are appropriately responding, negating claims of an emergency or the need for the Department to interfere, as discussed *infra* in Section C.[95] For example, PJM's, SPP's, and MISO's new "fast track" processes—adopted to address concerns of resource adequacy—"alone would add roughly twice what the DOE assumed for the entire nation."[96] The RAR is written arbitrarily and capriciously incorporating the implicit assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm.

In sum, Congress has explicitly reserved to the states and FERC primary regulatory authority over resource adequacy and reliability. The Department's only authority to directly regulate reliability of the electric grid is narrow emergency authority such as Federal Power Act Sections 202(c) and 215A. The Department does not have broader authority to interfere with resource adequacy or reliability regulations. To the extent that the RAR is the confirmation of the attempt to usurp that authority from the states and FERC, via a "uniform methodology" in the RAR, it is outside of DOE's statutory authority and contrary to law.

B. The Department's Findings in the RAR, Even if Accurate, Do Not Demonstrate Any Emergency Allowing the Department to Compel Generation Under the Federal Power Act.

Even if the findings in the RAR were accurate (which they are not, as explained in Section C below), they would not empower the Department to exercise any statutory authority, under "section 202 of the Federal Power Act" or otherwise, to override state- or market-driven changes to the electricity generating facilities supplying the grid.[97] As discussed in Section A above, the Federal Power Act gives the Department tightly circumscribed authority over resource adequacy planning, to address "emergency" conditions through "such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" as

---

[94] *See e.g.* DOE, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Energy Markets, at 3.8 (May 2002); GridLab, GridLab Analysis: Department of Energy Resource Adequacy Report, at 4 (July 11, 2025) (hereinafter "GridLab Analysis") (attached as Ex. 14).

[95] GridLab Analysis, Ex. 14 at 2-3.

[96] GridLab Analysis, Ex. 14 at 3.

[97] Grid EO at Sec. 3 (RAR, Ex. 1 at C-3).

"will best meet the emergency and serve the public interest."[98] The statutory text, structure, and history, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c), all establish that its "emergency" authority is confined to sudden, unexpected, imminent, and specific electricity shortfalls. The information in the RAR, at most, expresses the Department's view that bulk-power system reliability will be insufficient in 2030. The Department's conclusions in the RAR—even if assumed to be accurate for the sake of argument—consequently provide no basis for the Department to manipulate the electricity market.

1. The Federal Power Act only permits the Department to intervene when necessary to address an imminent, unexpected, and specific electricity shortfall.

The Federal Power Act's text, context, and structure, as well as caselaw and the Department's longstanding regulations, all establish that it does not permit the Department to "prevent" generating facilities "from leaving the bulk-power system" or "converting" from one fuel-source to another based on the Department's view of long-term reliability needs.[99] The Act provides the Department only authority to intervene in electricity markets when necessary to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response, through the cabined authority provided by Section 202(c) of the Act.

a. The Text of Section 202(c) Narrowly Limits the Department's Authority to Emergencies: Imminent, Unexpected, and Certain Shortfalls in Electricity Supply.

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected* appearance or occurrence . . . An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

[98] 16 U.S.C. 824a(c).

[99] Grid EO at Sec. 3(c)(ii) (RAR, Ex. 1 at C-4).

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[102]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power.[103] An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example.[104]

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*."[105] That near-term focus along with the statute's strictly "temporary" authority[106] precludes use of Section 202(c) to pursue long-term policy goals, such as "fear of overdependence" on foreign oil supplies,[107] or "energy independence."[108]

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course.[109] The resulting statutory "machinery for the

---

[102] Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Rolsma, Ex. 7 at 812 n.147 (noting that dictionaries have given the term "emergency" the "same meaning for many years").

[103] 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress").

[104] 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light,* 574 F.2d at 615 (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

[105] 16 U.S.C. § 824a(c) (emphasis added).

[106] 16 U.S.C. § 824a(c).

[107] *Richmond Power & Light*, 574 F.2d at 617.

[108] RAR, Ex. 1 at 1. *See Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

[109] 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & 824a(b)

promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[110]

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply,"[111] rather than mere want of more abundant supply in the future.[112] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future, or an expected "expansion of artificial intelligence data centers and an increase in domestic manufacturing,"[113]—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure.[114]

b. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.

That the Department's Section 202 powers may not be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements for the bulk-power system.[115] Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the

---

(allowing federal government to order "physical connection … to sell energy or to exchange energy" upon application, and after an opportunity for hearing).

[110] S. Rep. No. 74-621 at 49 (1935).

[111] *Id.*

[112] *cf.* Eddystone 202(c) Order, Ex. 9 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system").

[113] Grid EO at Sec. 1 (RAR, Ex. 1 at C-4).

[114] *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

[115] 16 U.S.C. § 824o.

federal government with the power to enforce measures designed to ensure broad, long-term reliability.[116]

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and operators of the bulk-power system" but with "fair stakeholder representation."[117] FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[118] Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational.[119] And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[120]

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of long-term bulk-system reliability would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section

---

[116] *See* 70 Fed. Reg. 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); RAR of the National Energy Policy Development Group (May 2001) at p. 7-6, https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system" for long-term reliability "to a mandatory rules system."). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[117] 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

202(c).[121] Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use long-term reliability concerns to mandate the generation it views as required to address long-term reliability needs.

c. DOE's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than a mechanism to address long-term concerns as to the reliability of the bulk-power system. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks.[122] Emergencies "may result" from a number of events.[123] The use of the verb "result," defined as "arise as a consequence, effect, or conclusion," suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur.[124]

Moreover, the events are characterized by those produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[125] Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation,"[126] rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its

---

[121] *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency].").

[122] 10 C.F.R. § 205.371 (emphasis added).

[123] *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

[124] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) 1063.

[125] 10 C.F.R. § 205.371

[126] *Id.* (emphasis added).

normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers."[127]

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning.[128] An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate to meet far-distant needs.[129] As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[130]

d. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978), arose out of the 1973 oil embargo. The Federal Power Commission needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England.[131] The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order.[132] The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition.[133] A dissatisfied utility

---

[127] 10 C.F.R. § 205.375 (emphasis added).

[128] 10 C.F.R. § 205.371 (also recognizing that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*" (emphasis added)).

[129] *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply).

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition.[134]

The court easily upheld the Commission's decision not to invoke Section 202(c).[135] Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order.[136] The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed.[137]

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency."[138] The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[139] Interpreting this statutory language, the court upheld the Department's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[140] Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period."[141] To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong section and should have used Section 202(c) instead.

---

[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

[138] *Id.* (emphasis added).

[139] *Id.*

[140] *Id.*

[141] *Id.* at 233-34.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency."[142] For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[143] The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

e. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.

The Department's past applications of Section 202(c) corroborate the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that section.[144] The Department's predominant practice outside of wartime has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[145] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment.[146]

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department

---

[142] *Id.* at 234 (citing 16 U.S.C. § 824a(c)).

[143] *Id.*

[144] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[145] *See, e.g.,* Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Ex.7 Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).

[146] *See, e.g.*, Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

views as necessary to ensure long-term resource sufficiency—and for good reason.[147] Any such use would exceed the Department's statutory authority.

2. In the RAR, DOE purports to identify only long-term, uncertain, and generalized concerns with bulk-power system reliability, which do not enable the Department to compel generation pursuant to Section 202(c).

Given the statutory limitations described above, the RAR provides no basis for the Department to use Section 202(c) to require that particular "generation resources" are "retained as an available generation resource," or to "prevent . . . an identified generation resource . . . from leaving the bulk-power system or converting" its fuel source.[148] Nor does the Department identify any other source of legal authority for DOE to impose such requirements. In the RAR, the Department only purports to identify capacity shortages that might affect bulk-system reliability in 2030.[149] The Department acknowledges that all but one region—ERCOT—currently meet its criteria.[150] Its claim that shortages might arise five years from now, even if it were correct—would present no "emergency" under Section 202(c). Those non-imminent resource needs are, rather, precisely the long-term reliability and resource adequacy matters over which Congress allocated responsibility to FERC and NERC.

Second, the Department identifies only a "risk of power outages" even in 2030[151] based on the Department's projected "AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth."[152] The Department acknowledges, meanwhile that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[153] The RAR—even by its own terms—thus does not specify any shortfall that is certain enough to justify invocation of the Department's emergency powers under Section 202(c). Its numbers are, rather, "indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."[154] Section 202(c) does not authorize the Department to order generation based on such non-certain shortfalls; it provides distinct, and

---

[147] *See Richmond Power and Light,* 574 F.2d at 616.

[148] Grid EO at 2.

[149] *E.g.,* RAR, Ex. 1 at 1, 20, 27, 30, 32, 40.

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

much more limited powers, by which the Department may facilitate "an abundant supply of electric energy throughout the United States."[155]

And third, the Department does not claim to identify any particular location in which a shortfall might occur, or the specific resources that might best serve to address such shortfall. Instead, in the RAR, the Department provides aggregate estimates of potential loss-of-load under "varied grid conditions and operating scenarios based on historical data."[156] But those estimates do not demonstrate that any single generating facility would best meet the resulting shortfall, and could not therefore justify an emergency order directing a facility to remain available.

Consequently—even setting aside methodological flaws—the Department asserts resource risks in the RAR that are neither imminent, certain, nor specific. Those risks do not describe an emergency that would permit the Department to intervene pursuant to Section 202(c). They represent, rather, the Department's view as to measures that might "assur[e] an abundant supply of electric energy throughout the United States."[157] Section 202 does not permit the Department to compel generation on that basis. The Department also describes in the RAR the measures the Department believes "necessary to provide for reliable operation of the bulk-power system."[158] But Section 215 gives FERC, not the Department, the power to provide for reliable operation of the bulk power system, and specifies the procedures by which such measures must be developed and enforced; the Federal Power Act does not permit the Department to end-run those limitations by deeming long-term reliability an emergency. The RAR consequently could not form the basis of any action by the Department to compel generation under Section 202 of the Federal Power Act.

C. The RAR Is Analytically Flawed and Does not Rely Upon Substantial Evidence.

The RAR is severely flawed and does not meet DOE's own information quality standards. There are significant informational and methodological limitations and clear analytical and data errors. Any reliance on the RAR to "guide interventions" or to serve as a basis for any DOE decisionmaking would be arbitrary and capricious and not based on substantial evidence, in violation of the Administrative Procedure Act.

---

[155] 16 U.S.C. § 824a(a).

[156] RAR, Ex. 1 at 2. *See, e.g., id.* at 21.

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

1. The RAR falls woefully short of informational and methodological best practices.

DOE admits the RAR was hastily thrown together without sufficient information. At the outset, DOE acknowledges the resource adequacy analysis in the RAR "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[159] Indeed, "[h]istorically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued."[160] DOE continues to explain that a key takeaway of the RAR is the need for "strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security."[161] The candor in these comments is revealing; these limitations prove that the RAR does not meet the requirements of the Information Quality Act ("IQA") or DOE's guidelines thereunder.[162] The RAR should be withdrawn so that the Department does not continue to disseminate this poor-quality information, and the RAR should not be relied on in any decisionmaking. In the alternative, the Department should not use the RAR as support for any final action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before releasing a final version that incorporates and responds to public comment.

The IQA directs agencies to "ensur[e] and maximiz[e] the quality, objectivity, and integrity of information (including statistical information) disseminated by Federal Agencies."[163] Office of Management and Budget ("OMB") guidelines issued

---

[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

[162] *See* Pub. L. 106-554 Sec. 515, 114 Stat. 2763A-153.

[163] *Id.* OMB's government-wide information quality guidelines direct agencies to issue their own implementing guidelines. Agencies must provide the public a way to administratively seek and obtain correction of information disseminated by the agency that does not comply with OMB or agency guidelines. *See* Office of Management and Budget, Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information, 67 Fed. Reg 8452 (Feb. 22, 2002); Office of Management and Budget, Memorandum for the Heads of Executive Departments and Agencies (Apr. 24, 2019) (hereinafter "OMB Guidelines 2019 Update"), https://www.whitehouse.gov/wp-content/uploads/2019/04/M-19-15.pdf.

Pursuant to the OMB directive, DOE has issued its own agency-specific information quality guidelines. *See* Dep't of Energy, Final Report Implementing Office of Management and Budget Information Dissemination Quality Guidelines (Oct. 1, 2002), no. 6450-01-p, https://www.energy.gov/sites/prod/files/cioprod/documents/finalinfoqualityguidelines03072011.pdf; Dep't of Energy, Final Report Implementing Updates to the Department of Energy's Information

pursuant to the IQA require agencies to ensure that scientific information including "factual inputs, data, models, analyses . . . related to such disciplines as . . . engineering, or physical sciences" undergo certain review procedures to maintain quality standards.[164]

To that end, agencies must "choose a peer review mechanism that is adequate, giving due consideration to the novelty and complexity of the science to be reviewed, the relevance of the information to decisionmaking, the extent of prior peer reviews, and the expected benefits and costs of additional review."[165] Agencies must "strive to ensure that their peer review practices are characterized by both scientific integrity and process integrity," including the "rationale and supportability" of the agency's findings and ensuring "avoidance of real or perceived conflicts of interest" and "a workable process for public comment and involvement."[166] Agencies are encouraged to "have the choice of input data and the specification of the model reviewed by peers before the agency invests time and resources in implementing the model and interpreting the results," in order to "focus attention on data inadequacies in time for corrections . . . before the agency becomes invested in a specific approach."[167] Additionally, peer reviewers must "ensure that scientific uncertainties are clearly identified and characterized," and "ensure that the potential implications of the uncertainties for the technical conclusions drawn are clear."[168] OMB IQA guidelines also require agencies to evaluate "the sensitivity of the agency's conclusions to analytic assumptions."[169] These steps of peer review determine a report's "fitness . . . for policy purposes."[170]

DOE IQA guidelines further note that "in disseminating certain types of information to the public, other information must also be disseminated in order to ensure an accurate, clear, complete, and unbiased presentation."[171] Agencies should provide open access to data and modeling information underlying a report.[172]

Quality Act Guidelines (2019) (hereinafter "DOE IQA Guidelines 2019 Update"), available at https://www.energy.gov/cio/articles/2019-final-updated-version-doe-information-quality-guidelines.

[164] OMB, Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664, 2667 (Jan. 14, 2005); *see also* OMB Guidelines 2019 Update at 4.

[165] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg. at 2668.

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

[172] OMB Guidelines 2019 Update at 8; *See also*, e.g., *Chem. Mfrs. Ass'n v. U.S. EPA*, 870 F.2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency."); *United States v. Nova Scotia Food*

Additionally, DOE is "responsible for ensuring that the information [being disseminated in a report] is consistent with the OMB and DOE guidelines and that the information is of adequate quality for dissemination."[173] For reports containing "influential financial, scientific, or statistical information," DOE must "identify for the [Chief Information Officer] a high ranking official" who is responsible for higher level review of the report's conclusions.[174]

OMB's IQA guidelines recognized that the "[f]ederal government's assessment of risk can directly or indirectly influence the response actions of state and local agencies or international bodies."[175] Thus, under the OMB and DOE guidelines, influential information—information routinely embargoed because of "potential effect on markets" or information "on which a regulatory action with a $100 million per year impact is based"—must meet the highest standards of quality and transparency, and should undergo the rigorous review procedures outlined above.[176]

Here, the RAR does not comply with IQA requirements, rendering any further reliance on it to be arbitrary and capricious. For example, the RAR appears to be inconsistent with internal review processes required: it should have undergone peer review because of its "influential" nature, particularly if the RAR is, as it purports to be, a "uniform methodology" to guide reliability interventions, such as Federal Power Act Section 202(c) orders, which have outsize economic impacts. However, there is no evidence that the RAR underwent any peer review, and, given the time constraints, it is unlikely it did. The Department further failed to make available all underlying data and modeling information used to create the RAR. Additionally, as described in detail below, the RAR relies on improper analytic assumptions, including overstated demand and understated supply forecasts. The RAR includes faulty analysis based on these improper assumptions despite DOE's acknowledgment of significant informational limitations regarding regional- and utility-level engineering data. In addition, the RAR contains numerous errors, such as referring to appendices that do not exist or incorrect appendices,[177] stating

---

Prods. Corp., 568 F.2d 240, 251-53 (2d Cir. 1977) (holding that regulation was promulgated in arbitrary and capricious manner where agency failed to disclose data on which it relied).

[173] DOE IQA Guidelines 2019 Update at 22.

[174] *Id.* at 22-23.

[175] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg at 2667.

[176] DOE IQA Guidelines 2019 Update at 7.

[177] *See* RAR, Ex. 1, at 12 (referring to nonexistent "Outputs" section of an unnamed appendix); *id.* (referring to Appendix B for further detail regarding retirement assumptions, whereas Appendix B describes Canadian transfer limits).

inaccurate units for generation capacity,[178] and falsely asserting bulk power system load shedding occurred in regions during certain events.[179]

2. In the RAR, the Department overstates assumptions about demand.

In the RAR, the Department assumes 101 GW of load growth by 2030—a 15% increase over 2025 load. This increase is more than double the high case in the U.S. EIA 2025 Annual Energy Outlook, which forecasts 6% growth.[180] This extraordinarily high assumed load growth contributes substantially to the findings of low resource adequacy under the Plant Closures scenario in the RAR. As explained below, in the RAR, the Department omits consideration of many factors that will likely dampen load growth in the coming 5 years, thus undermining the validity and usefulness of its results.

The Department assumes 50 GW of load growth from data centers by 2030, which it characterizes as the midpoint among other available forecasts.[181] However, it does not appear that DOE's forecast accounts for load flexibility at these data centers, which would significantly reduce the overall demand that these centers place upon the grid during the periods of peak system risk. While certain data centers may not be capable of load curtailment due to their purpose, many can be flexible. Even a small amount of data center load flexibility provides significant benefits. A recent study by experts at Duke University found that curtailment at data centers during only 0.25% of the year would enable 76 GW of data center power demand to be added to the system today, without triggering resource adequacy problems or requiring further expansion.[182] The White House recently issued an AI Action Plan endorsing demand flexibility as a means to maintain resource adequacy as data center capacity expands: "the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[183]

The Electric Power Research Institute has begun an initiative to enhance data center flexibility in light of its benefits for grid reliability, under which

---

[178] *Id.* at 9 (text stating that PJM has a shortfall of 2.4 MW).

[179] *See infra* subsection C.6.

[180] *See* GridLab Analysis, Ex. 14 at 2.

[181] RAR, Ex. 1 at 2.

[182] Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems at 20. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (attached as Ex. 15).

[183] White House, Winning the Race: America's AI Action Plan 15 (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

demonstration projects were set to deploy in the first half of 2025.[184] Early results from other projects to test data center flexibility have been promising.[185] Evaluations of the RAR by GridLab and the NYU Institute for Policy Integrity ("IPI") both have concluded that the Department's failure to account for data center load flexibility renders its findings of elevated reliability risk in 2030 suspect.[186] This is particularly true for DOE's findings concerning the ERCOT region, considering that in June 2025, Texas enacted a law allowing curtailment of these loads during grid emergencies.[187]

Furthermore, it is unclear whether the RAR's data center load forecasts account for potential constraints on the growth of data centers, such as shortages of critical semiconductor chips,[188] and other grid equipment like transformers and switchgears.[189] In addition to the Texas policy mentioned above, states and utilities are proposing new tariff designs for data centers to ensure that data centers don't

---

[184] Elec. Power Rsch. Inst., EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027.").

[185] *See* Anuja Ratnayake, Unlocking AI Potential with Data Center Flexibility, ENERGYCENTRAL (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-aipotential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance.").

[186] NYU Institute for Policy Integrity, *Enough Energy*, at 25 (attached as Ex. 16) (hereinafter "IPI Report"); *see also* GridLab Analysis, Ex. 14 at 2 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[187] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis, UTILITY DIVE (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[188] *See, e.g.* London Economics International LLC, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* at 39 (July 7, 2025) (attached as Ex. 17), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

[189] How big tech plans to feed AI's voracious appetite for power, The Economist (July 28, 2025), https://www.economist.com/business/2025/07/28/how-big-tech-plans-to-feed-ais-voracious-appetite-for-power.

pose risks to the distribution system or shift costs to other consumers, all of which could slow or redirect the forecasted data center load growth.[190] The Department fails to evaluate any of these dynamics in the RAR.

In addition to the overall rate of data center load growth, the Department also uses a poorly described and supported methodology to allocate data center load to different regions. As the IPI observes, DOE used state-level growth ratios to allocate the projected data center load across regions, "[b]ut it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load)."[191] IPI posits that "some computing demand may be served from other regions if it will be cheaper to integrate the data center elsewhere," and observes that "[g]iven the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets."[192] Figure 8 in the RAR (New Data Center Build) shows that DOE's estimates for the percentage of data center load growth that will be built in various RTOs in some cases differs substantially from the percentages in the various forecasts that DOE used to calculate its overall data center load growth estimate. DOE does not explain why it discards these studies' more geographically specific estimates and instead relies on a single state-level growth ratio derived from a different study.

The Department's approach to estimating non-data center load growth by 2030 is also poorly explained in the RAR and likely flawed. DOE relies upon NERC's 2024 Long-Term Reliability Assessment forecast for overall load growth, but because the Department otherwise seeks to include elevated levels of data center load growth in the RAR, it must back out an estimate of data center load growth from the overall forecast.[193] The estimate that DOE chooses to back out is a "low-growth" case for data center load from a different source (which DOE presents in volumetric consumption terms, rather than peak demand). This approach, without further information to understand DOE's analysis, could have resulted in DOE over-estimating non-data center load growth. This effect is likely exacerbated by recent changes in federal law that will reduce electricity consumption from

---

[190] Jason Plautz, *Rulemakers play catch-up as data centers multiply*, E&ENews by Politico (July 18, 2025), https://www.eenews.net/articles/rulemakers-play-catch-up-as-data-centers-multiply/.

[191] IPI Report, Ex. 16 at 26.

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.").

specific sectors, including vehicles and hydrogen electrolysis. The utility forecasts included in the NERC Long-Term Reliability Assessment included projections of vehicle and building electrification that depend in part on tax credits and incentives that were revoked prior to publication of the RAR as part of the One Big Beautiful Bill Act ("OBBBA"). Recent analysis shows that the elimination or reduction of tax credits that supported new sources of electricity load growth will have a meaningful effect by 2030.[194] As a result, DOE's non-data center load growth projections are likely overstated.

3. Assumptions about supply are unsupported.

a. In the RAR, the Department Overstates Likely Retirements.

The Department finds the most dire resource adequacy shortfalls occur in the Plant Closures case, in which it assumes 104 GW of retirements by 2030.[195] This estimate is much higher than the most recent data from the EIA released in June 2025 in its authoritative Form 860, which shows 50 GW fewer retirements than assumed in the RAR.[196] As GridLab experts explained, DOE assumed not only "these 50 GW of likely retirements, but [also] included another 50 GW of *announced* retirements."[197] While it may be appropriate to include announced retirements in certain long-term planning exercises, it is unreasonable to assume such retirements will happen as the basis for extraordinary emergency actions. Without more detail about any formal or binding characteristics of those announcements, or the factors purportedly driving those announcements, it is impossible to verify the validity of this input that doubles the amount of otherwise projected resource retirements. Even EIA's Annual Energy Outlook, which does model projected retirements beyond those already formally noticed, finds 10 GW fewer thermal retirements by 2030 than does DOE.[198] Without further support for the 50 GW assumed retirement

---

[194] *See, e.g.,* Princeton NetZero Lab and Evolved Energy Research, A Fork in The Road: Impacts of Federal Policy Repeal on the U.S. Energy Transition, at Tab 12 (last updated July 3, 2025), https://public.tableau.com/app/profile/evolvedenergyresearch/viz/AForkinTheRoad_ImpactsofFederalPolicyRepealontheU_S_EnergyTransition_June/1Title (showing approximately 100 TWh annual energy use reduction in 2030 compared to mid-range estimates of the status quo ante).

[195] RAR, Ex. 1 at 5.

[196] U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0. *See also* GridLab Analysis, Ex. 14 at 2.

[197] GridLab Analysis, Ex. 14 at 2; *see also* IPI Report, Ex. 16 at 24 (explaining that DOE's "number includes both 'confirmed' retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and 'announced' retirements—which are publicly stated but not officially noticed.").

[198] According to the U.S. EIA's 2025 Annual Energy Outlook, coal-fired generating capacity is projected to decline by 93.6 GW between 2025 and 2030 in the Reference case, approximately 10

value, the Plant Closures case is nothing more than speculation about what might happen if certain assumptions were to come true.

Such assumptions are particularly unjustified given that, as GridLab notes, "[m]ost likely many plants will choose not to retire due to the changing regulatory and economic landscape."[199] The IPI makes a similar point in their critique of DOE's retirement assumptions, noting that "the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources."[200] As one snapshot of this trend, high capacity prices in the PJM region led to 1.1 GW of resources withdrawing formal deactivation notices since last summer.[201] IPI also observes that the Trump Administration is seeking to rescind or reexamine many federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire before 2030, "which could cause resources to delay their retirements."[202]

b. In the RAR, the Department Understates Likely New Entry by 2030 and Other Sources of Supply.

Among the most impactful and unsupported assumptions in the RAR is that "only [generation] projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built" by 2030.[203] DOE thus constrains its analysis to include only projects designated as Tier 1 in the NERC 2024 Long Term Resource Assessment, which it then maps to Interregional Transfer Capability Study regions. Because Tier 1 includes only resources that are already under construction, have signed construction service agreements, and similar

---

fewer GW of retirements than modeled in the DOE report. No other fossil fuel technology shows a net decrease in generating capacity in the 2025 Annual Energy Outlook analysis. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[199] GridLab Analysis, Ex. 14 at 2.

[200] IPI Report, Ex. 16 at 24.

[201] PJM Inside Lines, PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal (July 22, 2025) https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("Since the 2025/2026 Base Residual Auction results were posted on July 30, 2024, 17 generating units totaling approximately 1,100 MW worth of Capacity Interconnection Rights have withdrawn their retirements").

[202] IPI Report, Ex. 16 at 24-25.

[203] RAR, Ex. 1 at 12.

characteristics,[204] this assumption "results in minimal capacity additions beyond 2026."[205] As experts at GridLab observe, the assumption that "no projects are built post 2026, [] is not realistic for a report forecasting to 2030."[206] This is especially true given rising energy prices due to increased demand, which is attracting more investment to the market and driving new construction of generation resources.

The Department also states in the RAR that of these Tier 1 additions, just 22 GWs of generator additions are "firm" (thermal) resources, which severely underestimates new gas generation compared to other projections. According to GridLab, "a more reasonable assumption for forecasted capacity additions is the EIA 860 released in June 2025, which has 35 GW of gas additions, and another 53 GW of batteries [for a total of] 88 GW of firm additions by 2030."[207] Other federal government projections are even higher: EIA's 2025 Annual Energy Outlook projects 90 GWs of new fossil generators added to the system through 2030.[208] 80 GWs of the EIA-projected natural gas growth are in earlier development stages and likely did not meet the 2024 NERC Long-Term Reliability Assessment Tier 1 criteria to be included in the RAR.

As researchers at the IPI conclude, DOE departed from best practice in declining to include any resources classified by NERC as "Tier 2" resources[209] in the overall resource adequacy analysis for 2030, even those at advanced stages of the interconnection process.[210] A reasonable process could have involved "examin[ing]

---

[204] *See* IPI Report, Ex. 16 at n.155 (citing NERC, 2024 Long Term Reliability Assessment, 137 (last updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[205] RAR, Ex. 1 at A-5.

[206] GridLab Analysis, Ex. 14 at 3.

[207] *Id.*

[208] According to the U.S. EIA, the policy-neutral reference case projects a 93.29 GW increase in combined cycle, fossil steam, and combustion turbine capacity between 2025 and 2030. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "Signed/approved Completion of a feasibility study, Signed/approved Completion of a system impact study, Signed/approved Completion of a facilities study, Requested Interconnection Service Agreement, Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[210] IPI Report, Ex. 16 at 23.

historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region."[211] For example, for the PJM region, the Independent Market Monitor's analysis shows that 15% of generation projects (on an energy basis) successfully enter service.[212] As of late 2024, PJM had over 44 GW of accredited capacity in its interconnection queue.[213] To assume that none of this capacity would enter service by 2030, as DOE's analysis does, is unreasonable.

Such an analysis should also consider factors pointing towards even faster queue times than those seen in the historical data, given factors now expediting interconnection queues such as implementation of FERC Order 2023, streamlining of tools to better utilize existing points of interconnection (e.g., surplus interconnection service), and various interconnection fast tracks that FERC has recently approved.[214] For example, it is unreasonable for DOE to exclude from consideration the over 9 GW of accredited capacity that PJM selected in May 2025 to participate in its Reliability Resource Initiative—the vast majority of these projects (primarily gas and battery energy storage systems) are committed to be online by 2030,[215] but are omitted in DOE's analysis because they do not yet have a signed interconnection agreement. DOE paints an inaccurate picture of new entry by ignoring recently adopted policies designed to address the very same tightening supply and demand conditions that DOE describes.

DOE also underestimates the extent to which interregional transfers of energy could help to prevent or address any shortfalls. Noting that it relies upon the interregional transfer capacities identified by NERC in its Interregional Transfer Capability Study, DOE explains that "[i]mports are assumed to be available up to the minimum total transfer capacity and spare generation in the

---

[211] *Id.*

[212] Monitoring Analytics, 2024 State of the Market Report, at 705 (2024) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm-sec12.pdf (noting 14.9% completion rate).

[213] PJM, Reliability Resource Initiative MRC Update, at slide 6 (Nov. 7, 2024) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-04---reliability-resource-initiative---presentation.ashx.

[214] *Id. See also* Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at 4 (May 27, 2025), https://www.ferc.gov/media/manu-asthana-pjm-president-and-ceo (touting recent improvements to PJM's interconnection queue by noting that "[a]n additional approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional 56 GW (including projects from Transition Cycle 2 and Reliability Resource Initiative) will be through the queue by late 2026.").

[215] PJM, Reliability Resource Initiative Results Summary, at slide 9 (May 6, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

neighboring subregion."[216] Because the Interregional Transfer Capability Study calculated interregional transfer capacities for both summer and winter, and for each direction of flow, it is unclear what DOE means regarding allowing transfers up to the minimum. As the IPI observes: "If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity."[217] This is yet another example of where DOE fails to explain its methodology with sufficient detail to enable an evaluation of whether its approach is reasonable, or is supported by substantial evidence.

4. DOE's use of a deterministic analysis provides an incomplete and inaccurate picture.

For the RAR, DOE employs a deterministic approach in examining resource adequacy; that is one that "evaluate[s] resource adequacy using relatively stable or fixed assumptions about the representation of the power system," rather than a probabilistic approach that "incorporate[s] data and advanced modeling techniques to represent uncertainty that require more computing power."[218] DOE explains it chose a deterministic approach "for transparency and to model detailed historic system conditions."[219] However, deterministic approaches have significant limitations; as NERC explained in the Interregional Transfer Capability Study on which DOE otherwise heavily relies, because that study did not employ a probabilistic approach, it "should not be considered a North American resource adequacy assessment."[220] The problem, as IPI explains, is that "[b]y examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty."[221] Furthermore, as NERC itself has explained, under a deterministic approach, "some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future."[222] As IPI concludes, neither of DOE's professed reasons for using a deterministic approach justifies departing from best practices, as "DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach."[223]

---

[216] RAR, Ex. 1 at 12.

[217] IPI Report, Ex. 16 at 26.

[218] RAR, Ex. 1 at 2 n.2.

[219] *Id.*

[220] IPI Report, Ex. 16 at 21 (citing NERC, Interregional Transfer Capability Study, at 4 (2024) (hereinafter "NERC ITCS")).

[221] IPI Report, Ex. 16 at 21.

[222] *Id.* (citing NERC ITCS at 138).

[223] *Id.* at 21.

DOE may have chosen a less sophisticated and rigorous approach given the limited amount of time in which the Grid EO required this analysis to be completed, but regardless of the reason, the limitations inherent in DOE's deterministic methodology mean that its findings should not be taken as conclusive or form the basis for further extraordinary actions.[224]

5. DOE uses an elevated threshold for determining when outages will occur.

In the RAR, the Department projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[225] This approach, and the particular values used as thresholds, come from the NERC Interregional Transfer Capability Study, which uses 3% as the default threshold and 6% only in a sensitivity analysis. NERC explains that the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" in order for a Balancing Authority to continue to hold the minimum reserves needed to protect the system from cascading or widespread outages.[226] In the sensitivity examined by NERC, using the 6% threshold "significantly altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida."[227]

As the IPI analysis notes, DOE provides no further explanation for when and how it uses 6% as a threshold versus 3%.[228] While the Department directs readers to an appendix with further detail, the appendices do not in fact provide any further information regarding this critical assumption.[229] Furthermore, "the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis," and that if "DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate the extent of expected outages."[230] DOE's failure to explain its own methodology concerning such a critical input to its analysis, including through the failure to provide information in an appendix that the RAR states exists, renders the RAR arbitrary and capricious. Insofar as the RAR's results for 2030 scenarios depend upon the 6% threshold, DOE must explain why

---

[224] *Id.* ("Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.")

[225] RAR, Ex. 1 at 12.

[226] IPI Report, Ex. 16 at 22 (citing NERC ITCS, at 91 n.90, 85).

[227] IPI Report, Ex. 16 at 22 (citing NERC ITCS at 105 tbl.8.4); *see also id.* ("Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.")

[228] IPI Report, Ex. 16 at 22.

[229] *Id.*

[230] *Id.*

such a threshold is appropriate, given the departure from NERC's practice and the evidence in the NERC report considering the propriety of a far lower threshold.

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

---

[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year.").

[234] PJM Inside Lines, PJM Releases Winter Storm Elliott Report (July 17, 2023) https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ ("PJM maintained system reliability and served customers throughout the extreme weather that affected the region Dec. 23–25 [2022], and even was able to support its neighbors during certain periods."); *see also* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (noting that PJM was exporting power to neighboring regions during Winter Storm Uri, and investigating rolling blackouts only in Texas and south central states).

[235] RAR, Ex. 1 at 5.

[236] IPI Report, Ex. 16 at 20.

D. Notice and Comment Procedures Are Required for Any "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the Administrative Procedure Act, federal agencies must provide notice and an opportunity for public comment when issuing rules, with limited exceptions not applicable here.[237] If the RAR is, as the Department claims on page vi, a "uniform methodology" for agency decisionmaking on reliability interventions, then the Department needed to provide notice and seek and respond to public comment on this methodology. The Department cannot slip in "entirely new information critical" to its "determination[s]" without taking and responding to public comment.[238]

In the past, when the Department sought to create uniform triggers for reliability intervention within its authority, it issued notice and sought comment.[239] If the RAR is a "uniform methodology" for reliability interventions, then the Department has effectively amended those prior regulations on reliability interventions without following legally required procedures. For example, the Department has regulations defining "emergency" and setting forth procedures for an applicant to demonstrate an "emergency" in the context of Federal Power Act Section 202(c) orders.[240] If the RAR is now a mandatory factor in determining whether there is an "emergency," the Department has changed its existing regulations without following required notice and comment procedures.

E. NEPA Procedures Must Be Followed for Any RAR on Legislative Proposals or "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the National Environmental Policy Act ("NEPA"), agencies must include a "detailed statement" on the environmental impacts of a proposed action "in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[241] If the RAR is a "uniform methodology" for agency decisionmaking on reliability interventions, it qualifies as a major federal action requiring, at a minimum, an Environmental Assessment and most likely, under the circumstances, a full

---

[237] 5 U.S.C. §§ 553(b), (c).

[238] *Am. Pub. Gas Assoc. v. DOE*, 72 F.4th 1324, 1338 (D.C. Cir. 2023) (cleaned up).

[239] *See* Grid Security Emergency Orders: Procedures for Issuances, 83 Fed. Reg. 1174 (Jan. 10, 2018) (final rule on Federal Power Act section 215A procedures issued after notice and comment); Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984 (Aug. 6, 1981) (final rules concerning emergency interconnections under Federal Power Act sections 202(c) and 202(d) issued after notice and comment).

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

Environmental Impact Statement. However, the RAR does not contain any statement whatsoever, and certainly no "detailed statement," on environmental impacts.

Yet the RAR purports to guide "government decisionmakers" on one of the most significant issues that affect the environment—electricity generation. The electricity sector is responsible for wide-ranging environmental impacts—from smog to greenhouse gas emissions to toxic metals to acid rain.[242] Uniform rules on reliability interventions would significantly affect the environment because some of these reliability interventions allow environmental rules for electricity generators to be waived.[243]

VI. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department withdraw the RAR. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) provides a detailed explanation of the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

Dated: August 8, 2025

Respectfully submitted,

/s/ Caroline Reiser
Caroline Reiser
Simi Bhat
Gavin McCabe
Karen Chen
Natural Resources Defense Council
1152 15th Street NW, Suite 300
Washington, DC 20005
creiser@nrdc.org
sbhat@nrdc.org
gmccabe@nrdc.org
kchen@nrdc.org
(202) 717-8341

[242] *See* EPA, Human Health & Environmental Impacts of the Electric Power Sector (Feb. 6, 2025) https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector.

[243] *See* 16 U.S.C. § 824a(c)(4)(A).

/s/ Alexis S. Blizman
Alexis S. Blizman
Policy Director
Ecology Center
339 E. Liberty, Suite 300
Ann Arbor, MI 48104
alexis@ecocenter.org
(734) 369-9281

/s/ Ted Kelly
Ted Kelly
Tomás Carbonell
Environmental Defense Fund
555 12th St. NW, #400
Washington, DC 20004
tekelly@edf.org
tcarbonell@edf.org
(202) 387-3500

/s/ Bradley Klein
Bradley Klein
Managing Attorney
Environmental Law & Policy Center
35 E. Wacker Dr., Suite 1600
Chicago, IL 60601
bklein@elpc.org
(312) 420-5503

/s/ Tyson Slocum
Tyson Slocum
Public Citizen, Inc.
215 Pennsylvania Ave SE
Washington, DC 20003
tslocum@citizen.org
(202) 454-5191

/s/ Sanjay Narayan
Sanjay Narayan
Gregory E. Wannier
Sierra Club Environmental Law Program
2101 Webster St., Ste 1300
Oakland, CA 94612
sanjay.narayan@sierraclub.org
greg.wannier@sierraclub.org
(415) 977-5646

/s/ William Kenworthy
William Kenworthy
Senior Regulatory Director, Midwest
Vote Solar
1 South Dearborn St., Suite 2000
Chicago, IL 60603
will@votesolar.org
(704) 241-4394

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 100
NIPSCO 2024 IRP

150 West Market Street, Suite 600
Indianapolis, IN 46204

December 9, 2024

Via Email Delivery – bborum@urc.in.gov

Dr. Brad Borum, Director
Research, Policy and Planning Division
Indiana Utility Regulatory Commission
PNC Center
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204

Re: Northern Indiana Public Service Company LLC
2024 Integrated Resource Plan

Dear Dr. Borum:

In accordance with 170 IAC 4-7 ("IRP Rules"), Northern Indiana Public Service Company LLC ("NIPSCO") is submitting via email transmission its redacted Integrated Resource Plan ("IRP") (Volume 1). NIPSCO's IRP reflects the assessment of supply- side and demand-side resources to meet NIPSCO's customers' electric service needs.

The nonredacted version of NIPSCO's IRP is the subject of a petition being filed contemporaneous with this email transmission of the redacted version of its IRP. Once NIPSCO has received approval for confidential treatment of its IRP, a nonredacted version will be submitted under seal. This procedure is at the request of the Commission staff.

By copy of this letter, NIPSCO is providing to the Commission the information required by 170 IAC 4-7-2(c). The organizations or individuals NIPSCO considered to be interested parties are included on an enclosure included with this letter. This list was determined based on organizations or individuals that participated in NIPSCO's IRP process.

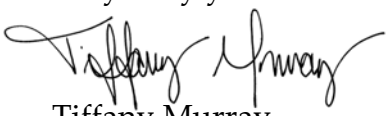
By copy of this letter, which NIPSCO is sending via electronic mail, NIPSCO notifies the interested parties that it has submitted an IRP to the Commission that is generally described above and the redacted copy of NIPSCO's IRP can be viewed / downloaded at https://www.nipsco.com/irp. The Commission invites an interested party

to submit written comments on NIPSCO's submitted IRP. The Commission will provide notice of the IRP and the due date for the submission of written comments pursuant to the publication requirements of Ind. Code § 8-1-1-8. 170 IAC 4-7-2.2 provides for a ninety (90) day period, or longer as determined by the Commission, to submit written comments.

In accordance with 170 IAC 4-7-2(d)(3), NIPSCO is serving via email transmission its redacted IRP (Volume 1) on the Indiana Office of Utility Consumer Counselor ("OUCC"). A nonredacted copy of NIPSCO's IRP (Volume 2) is also being provided to the OUCC pursuant to the Standard Form Nondisclosure Agreement between NIPSCO and the OUCC dated August 6, 2006.

NIPSCO has submitted an IRP that is intended to contain the information required by the Commission's IRP Rules. If the Commission, its Staff, or any interested party believes that NIPSCO's IRP needs clarification in some respect, please contact Erin Whitehead at (317) 965-8334 or via email at ewhitehead@nisource.com

Very truly yours



Tiffany Murray

Enclosures

Contact First Name	Contact Last Name	Contact Email Address	Company
Denise	Abdul-Rahman	darahman17@gmail.com	Indiana State Conference of the NAACP
Denise	Abdul-Rahman	denise@blacksunlight.org	Black Sun Light Sustainability
Denise	Abdul-Rahman	darahman17@gmail.com	Indiana NAACP
Levy	Agaronnik	Levy.agaronnik@blackstone.com	Blackstone
Shannon	Anderson	shannon@earthcharterindiana.org	Earth Charter Indiana
Cynthia	Armstrong	carmstrong@oucc.in.gov	Indiana OUCC
Laura	Arnold	Laura.Arnold@IndianaDG.net	Indiana Distributed Energy Alliance
Pat	Augustine	paugustine@crai.com	Charles River Associates
Ryan	Baker	Ryanbaker@usw12775.org	
Quinn	Beckham	quinn.beckham@keycaptureenergy.com	Key Capture Energy
Michael	Beeler	mbeeler@urc.in.gov	IURC
Amanda	Bersing	amanda.bersing@wellsfargo.com	Wells Fargo Securities
Geraldine	Black	babygirlhosea@gmail.com	
Marc	Blanchard	marc.blanchard@bp.com	BP
Alexandra	Boillot Navin	alexandra@rangerpower.com	Ranger Power
Jean	Boling	jboling1@urc.IN.gov	Indiana Utility Regulatory Commission
Bradley	Borum	bborum@urc.in.gov	IURC
Drew	Burczyk	dcburczyk@burnsmcd.com	Burns and McDonnell
Jonathan	Burke	jburke@tac.nrg.com	Tactical Energy Group, Inc.
Taylor	Carpenter	tcarpenter@calfee.com	Calfee
Gilles	Charriere	Gillescharriere@yahoo.com	
Chris	Chyung	chris@inconservationvoters.org	ICV
Richie	Ciciarelli	rciciarelli@veritionfund.com	Verition
Christine	Colon	colongar@aol.com	
Jordan	Covely	jordan.covely@inovateus.com	Inovateus Solar LLC
Joan	Crist	cristjoan1@gmail.com	
Anaelle	Croteau	acroteau@advantagecap.com	AdvantageCapital
Garrett	Culp	gculp@indianaenergy.org	Indiana Energy Association
Bruna	da Silva	bruna.dasilva@keycaptureenergy.com	Key Capture Energy
Roy	Dell'Aquila	ROYDELLAQUILA@YAHOO.COM	
Lou	Donkle	donkle3@gmail.com	none
Paul	Dort	paul.dort@edp.com	EDP Renewables North America
Sameer	Doshi	sdoshi@earthjustice.org	Earthjustice
Carol Sparks	Drake	CaDrake@oucc.IN.gov	Indiana Office of Utility Consumer Counselor
Cory	Dutcher	cory.dutcher@ge.com	GE Vernova / GE Gas Power
Stephen	Dynako	dynako@gmail.com	Stephen Dynako
Michael	Eckert	meckert@oucc.in.gov	OUCC
Suzanne	Escudier	suzanne.escudier@origisenergy.com	Origis Energy
Hadiza	Felicien	hfelicien@formenergy.com	Form Energy
Brian	Flory	bflory@solarunitedneighbors.org	Solar United Neighbors
McKenzie	Fowler	mfowler@crai.com	CRA
Steve	Francis	Sierrasteve@comcast.net	SEED - Sustainable Energy and Economic Development
Ray	Fu	rfu@bamfunds.com	Balyasny
Erik	Gage	egage@nationalgridrenewables.com	National Grid Renewables
Aditya	Gandhi	agandhi@wolferesearch.com	Wolfe Research
Eliza	Gedney	elizagedney@gmail.com	CRA
Aidan	Gibbons	agibbons@crai.com	Charles River Associates
Lucas	Giese	lugiese@iu.edu	
Richard	Gillingham	rgillingham@hepn.com	Hoosier Energy
Elena	Gomez	elena.gomezescalonilla@x-elio.com	X-ELIO
Elena	Gomez	elena.gomezescalonilla@x-elio.com	X-ELIO
Emma	Goodnow	emma.goodnow@duke-energy.com	Duke Energy
Doug	Gotham	gotham@purdue.edu	State Utility Forecasting Group
Kimberly	Graham	akgraham7@comcast.net	
Donald JACK	Groves	poweresi@comcast.net	ENERGY SOUTHWEST INC.
Karen S	Hall	Karen.Hall2@duke-energy.com	Duke Energy
Leslie	Hamby	leslie.hamby@centerpointenergy.com	CenterPoint Energy
John	Hanks	Jhanks@oucc.in.gov	OUCC
Michael	Hardie	michael.hardie@aes.com	AES Indiana
Frank	He	fhe@orionrenewables.com	

Contact First Name	Contact Last Name	Contact Email Address	Company
Steph	Hodgin	stehodgin@urc.in.gov	IURC
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
James	Huston	jhuston1@urc.in.gov	IURC
Ben	Inskeep	binskeep@citact.org	Citizens Action Coalition
John	Isaac	john.isaac@leewardenergy.com	2/2/2024
Evan	Iskenderian	evan@rangerpower.com	Ranger Power
David	Jackson	djackson@flexgen.com	Flexgen, Inc.
Jeff	James	jjames@savionenergy.com	Savion, LLC
Christopher	Jeffrey	christopher.jeffrey@mizuhogroup.com	Mizuho Securities
Alexandra	Jones	ajones@boselaw.com	Bose, McKinney, & Evans LLP
Michelle	Kang	michelle.kang@earthriseenergy.com	Earthrise Energy, PBC
Kelley	Karn	kelley.karn@duke-energy.com	Duke Energy
Tony	Kazakevicius	tkaz@anacostia.com	Chicago South Shore & South Bend Railroad
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Genevieve	Kennedy	genevieve.kennedy@leewardenergy.com	Leeward Renewable Energy
Will	Kenworthy	will@votesolar.org	Vote Solar
Nick	Kile	Nicholas.kile@btlaw.com	Barnes & Thornburg
Mo	Klefeker	mklefeker@primaryenergy.com	Primary Energy
Tim	Koenning	tkoenning@npca.org	
Gregory	Krieger	gkrieger@oucc.in.gov	Indiana OUCC
Nikhil	Kumar	nikhil@gridlab.org	GridLab
Reagan	Kurtz	rkurtz@citact.org	Citizens Action Coalition of Indiana, Inc.
Brian	Latham	blatham@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Derek	Leader	dleader@oucc.in.gov	OUCC
Robert	Leah	bleah@nationalgridrenewables.com	National Grid Renewables
Robert	Lee	rlee@crai.com	Charles River Associates
Max	Lee	max.lee@edp.com	EDP Renewables
Sally	Lei	sally.lei@nexteraenergy.com	Nexetra Energy Resources
Michael	Leikin	mike.leikin@electrotempo.com	ElectroTempo
Spark	Li	sli8@jefferies.com	Jefferies
Jeff	Lichy	jlichy@bluegrottocapital.com	blue grotto
Edward	Locigno	ejlocigno@aep.com	Indiana Michigan Power Company
Arthur	Longthorne	Alongthorne@solscient.com	Solscient Energy
Earl	M Miller	emiller@hilerindustries.com	Accurate Castings, Inc.(Hiler Ind.)
Sunil	Maheshwari	mahesh67@purdue.edu	Purdue University
Bill	Malcolm	wmalcolm@aarp.org	AARP
Jeremy	Martin	jeremy.martin@centerpointenergy.com	CenterPoint Energy
Davis	McCourt	davis@rangerpower.com	Ranger Power
Emily	Medine	emedine@evainc.com	Energy Ventures Analysis, Inc.
Zachary	Melda	zachary.melda@nexteraenergy.com	NextEra energy
Dan	Mellinger	dmellinger@energyfuturesgroup.com	Energy Futures Group
Tony	Mendoza	tony.mendoza@sierraclub.org	Sierra Club
Erik	Miller	erik.miller@aes.com	AES
Bryan	Mills	bryan.mills@nexteraenergy.com	NextEra Energy Resources
Alan	Mok	alan.mok@duke-energy.com	Duke Energy
Mike	Mooney	mmooney@hepn.com	Hoosier Energy
Joe	Motuliak	joe.motuliak@nee.com	NextEra Energy Resources
Edwin	Moyo	emoyo@crai.com	CRA International
David	Nderitu	nderitu@purdue.edu	State Utility Forecasting Group
Kay	Nelson	knelson@nwiforum.org	Northwest Indiana Forum
Ren	Norman	rnorman@urc.in.gov	Indiana Utility Regulatory Commission
Christopher	Norrick	cnorrick@solarunitedneighbors.org	Solar United Neighbors
Jessica	Nyquist	jnyquist@formenergy.com	Form Energy
Kerwin	Olson	kolson@citact.org	Citizens Action Coalition
lois	osborn	bornsoil@gmail.com	
Nadia	Pabst	NPabst@aypa.com	Aypa Power
April	Paronish	aparonish@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Richard	Pate	rgpate@pateassociates.com	Pate & Associates
Harshil	Patel	harshil.patel@leewardenergy.com	Leeward Renewable Energy

Contact First Name	Contact Last Name	Contact Email Address	Company
Mary	Perren	mary.perren@gmail.com	Hoosier Solar
Matthew	Peterson	Matthew.Peterson@duke-energy.com	Duke Energy
Ryan	Pfefferle	rypfefferle@microsoft.com	Microsoft
Tim	Phillips	timphillips@purdue.edu	State Utility Forecasting Group
Timothy	Powers	tim.powers@inovateus.com	Inovateus Solar LLC
Govind	Ramakrishnan	govind.ramakrishnan@blackstone.com	Blackstone
Tolaver	Rapp	tolaver.rapp@clevelandcliffs.com	Cleveland-Cliffs
Greg	Reiss	greiss@veritionfund.com	
Matt	Rice	matt.rice@centerpointenergy.com	CenterPoint Energy
Thomas	Rickabaugh	thomas.rickabaugh@edf-re.com	EDF Renewables
Chad	Ritchie	chad.ritchie@oracle.com	Oracle
Stephen	Rodocanachi	srodo@hartreepartners.com	Hartree Partners, LP
Colleen	Rosales	cmfrosales@gmail.com	OpenAQ / University of California in Davis
Roopali	Sanka	rsanka@oucc.in.gov	OUCC
Maxwell	Santiago	maxsanti@iu.edu	
David	Savage	dsavage@urc.in.gov	Indiana Utility Regulatory Commission
Zach	Schalk	Zach@solarunitedneighbors.org	Solar United Neighbors
Andrea	Schroeder	andrea.schroeder@engie.com	ENGIE
Carter	Scott	carter@rangerpower.com	Ranger Power LLC
Donnita	Scully	donnita4sfhs@hotmail.com	NAACP LaPorte County Branch
Zico	Shaker	zico.shaker@leewardenergy.com	Leeward Renewable Energy
Sebastien	Sherman	Sebastien.Sherman@Blackstone.com	Blackstone
Joshua	Siegel	joshua.siegel@bp.com	BP
Mark	Simons	mcsimons803@gmail.com	MCSimons Inc
Regiana	Sistevaris	rsistevaris@aep.com	I&M
Steven	Smith	smiste@mac.com	Franklin Covey
Jesse	Smith	jsmith@demandsideanalytics.com	Demand Side Analytics, LLC
Jeffrey	Solomon	jsolomon@savionenergy.com	Savion LLC
Anna	Sommer	asommer@energyfuturesgroup.com	Energy Futures Group
Oliver	Stover	ostover@crai.com	CRA
Spencer	Summers	ssummers@nwiforum.org	Northwest Indiana Forum
Joshua	Swanson	joshua.swanson@centerpointenergy.com	CenterPoint Energy
Will	Talbott	wtalbott@aypa.com	Aypa Power
Dale	Thomas	dthomas@urc.in.gov	IURC
Susan	Thomas	Susan@jtnwi.org	Just Transition NWI
Quintin	Thompson	quintin.thompson@aes.com	AES IN
Edward	Twarok	ehtwarok@comcast.net	Retired
Gregory	Va Horssen	gvhorssen@vanhorssenlaw.com	Van Horssen Law & Government, PLLC
Marco	Velastegui	mvelaste@purdue.edu	Purdue
Nathan	Vogel	nathan.vogel@inovateus.com	Inovateus Solar LLC
Connor	Ward	cward@advantagecap.com	Advantage Capital
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana
Doug	Wester	doug@nationalgridrenewables.com	National Grid Renewables
Kristina	Wheeler	kwheeler@boselaw.com	Bose McKinney & Evans LLP
Andy	White	andrew.white@leewardenergy.com	LRE
Theodore	Why	twhy@crai.com	Charles River Associates
Ryan	Wilhelmus	ryan.wilhelmus@bigrivers.com	Big Rivers Electric Corporation
Rachel	Wilson	rwilson@formenergy.com	Form Energy
Luke	Wilson	LuWilson@urc.IN.gov	Indiana Utility Regulatory Commission
Brian	Wright	brwright@oucc.in.gov	OUCC
J. Scott	Yaeger	scott.yaeger@rocklandcapital.com	Rockland Capital
Gilbert	Zelaya	gzelaya@earthjustice.org	Earthjustice
Micheal	Zhang	micheal.zhang@blackstone.com	Blackstone



Integrated Resource Plan

NIPSCO 2024 SUMMARY

NIPSCO®
A NiSource Company

NIPSCO.com/IRP

BACKGROUND

For a balanced, sustainable energy future, NIPSCO is committed to transitioning to diverse, cleaner energy solutions in a manner that is driven by real-world data and economics and that ensures continued protections and benefits to the customers and communities we serve across Northern Indiana. NIPSCO presents this Integrated Resource Plan, or IRP, to the Indiana Utility Regulatory Commission (IURC) every three years.

Since NIPSCO introduced our last plan in 2021, we've continued to build out our electric generation portfolio with the completion of wind, solar, and storage projects and gained regulatory approval for our natural gas peaking resource that will be located at the R.M. Schahfer Generating Station property. We look forward to soon adding more renewable energy resources to our portfolio, including battery storage technology that will support the safety and reliability of the energy we provide.

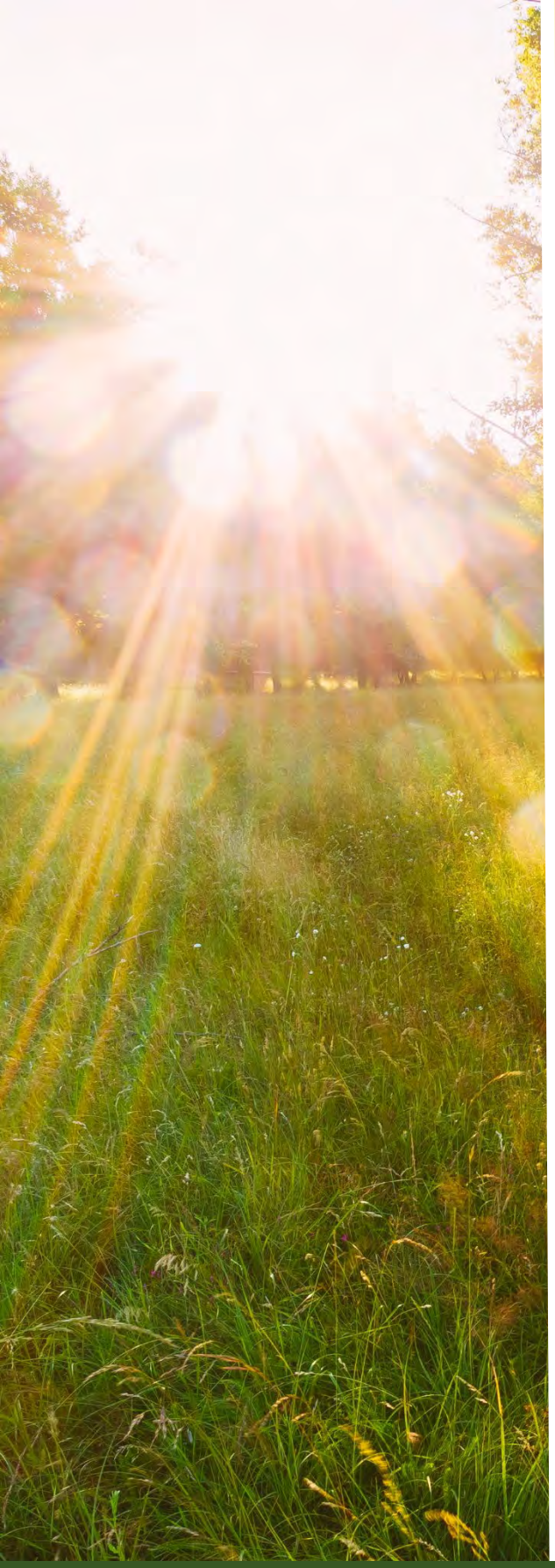
As we evolve alongside our communities and the rapidly changing energy landscape, we use a forward-looking analysis framework to create our updated IRP, which establishes a roadmap for near-term electric portfolio decisions and our long-term vision. Our process involves a comprehensive analysis of our future energy mix, informed by valuable input from numerous stakeholders including customers, regulators and local community leaders.

NIPSCO's IRP outlines a path that keeps our customers' best interests at the forefront and allows NIPSCO to be flexible as we move forward. As new load comes on to NIPSCO's system and as regulations continue to evolve, we will ensure we have the appropriate generation resources to meet the reliability and energy needs of all of our customers.

EVOLVING ALONGSIDE OUR COMMUNITIES

The modeled portfolios throughout the IRP are regulatory requirements made in connection with integrated resource planning that contain the Company's forward-looking assumptions. These modeled portfolios are not an indication of actual future events and should not be relied upon as such.





ABOUT THE 2024 INTEGRATED RESOURCE PLAN

Our IRP charts a path to best meet the energy needs of our customers for the next 20 years, and it is updated every three years. The 2024 plan reflects the dynamic changes taking place in the electric industry, the changing needs and behaviors of our customers, and evolving policy and market rules.

Our 2024 IRP captures this evolving environment and creates a highly flexible plan that achieves the following:

- Maintains the window to retire all remaining coal-fired generation by 2028, with our largest remaining plant retiring by 2025
- Retires aging gas peaking units by 2027
- Continues replacement of retiring generation resources with a diverse, flexible, and scalable mix of incremental resources, including short-term contracted capacity resources, expanded demand side management programs, solar, large battery storage, and new natural gas peaking resources
- Prepares for potential hyperscaler data center load with a combination of baseload and peaking natural gas generation, battery storage, and renewable capacity
- Explores potential alternatives on the path toward further decarbonization of the generation portfolio, including hydrogen generation, carbon capture, and emerging energy storage technologies
- Positions the portfolio to meet reserve margin obligations associated with Midcontinent Independent System Operator Inc.'s (MISO) new Direct Loss of Load (D-LOL)[1] market construct, which will materially impact resource accreditation and NIPSCO's seasonal load obligation
- Prepares for compliance with the Environmental Protection Agency's (EPA) Greenhouse Gas (GHG) rule and provides NIPSCO flexibility for several potential pathways toward its Net Zero emissions target based on potential future technological developments

[1] On October 28th, 2024, the Federal Energy Regulatory Commission (FERC) approved MISO's D-LOL methodology for calculating and awarding capacity value to generating facilities. This new method of capacity accreditation will impact intermittent resources most significantly.

ABOUT NIPSCO

Approximately 500,000 Northern Indiana homes and businesses in 32 counties depend on NIPSCO each day for safe, reliable and affordable energy.

NIPSCO IS INTEGRATED INTO THE BROADER ENERGY MARKETPLACE

NIPSCO's service territory and resources are part of the MISO power market, specifically located within Local Resource Zone 6 (LRZ6), covering Indiana and parts of Kentucky. Independent System Operators (ISOs) like MISO perform the following key roles:

- Ensure the reliability of the electric system by complying with Federal Energy Regulatory Commission (FERC) Orders and North American Electric Reliability Corporation (NERC) Reliability Standards;
- Oversee markets for energy, capacity, ancillary services, and transmission rights; and
- Direct the daily operation of the electric system, including plant dispatch.

Therefore, as a member of MISO, NIPSCO is not independently responsible for system reliability and market operations. However, NIPSCO must offer its resources into the MISO capacity and energy markets, respond to MISO signals and instructions, and comply with a dynamic set of market rules and standards. In addition, as a Transmission Operator (TOP), NIPSCO is responsible for directly complying with a variety of NERC standards associated with reliability.

The MISO market is currently in the midst of significant change, meaning that NIPSCO must navigate its own portfolio decisions while recognizing the dynamic external environment. These MISO changes include:

- A system-wide transition away from coal and towards more intermittent renewable resources
- The emergence of new technologies with operating profiles that are very different from traditional generation resources like coal and natural gas
- The evolution of market rules to accommodate these changes, such as:
    - Development of new methods of calculating capacity credit for resources
    - Establishment of participation models for distributed energy resources (DER) and long-duration storage energy resources (LDES)

Given the uncertainties associated with future MISO market changes, it is critical that NIPSCO ensure resource planning decisions are flexible enough to adapt over time.

NIPSCO'S 2024 INTEGRATED RESOURCE PLAN APPROACH

Resource planning is a complex undertaking, one that must address the inherent uncertainties and risks that exist in the evolving electric industry landscape. In the 2024 IRP, several key themes shaped the way NIPSCO approached the development of its preferred plan and the supporting analysis. These included a focus on:

- **Long-Term Planning with Intermittent Resources**, particularly associated with understanding the system reliability implications of intermittent resources under MISO's D-LOL capacity accreditation methodology
- **Carbon Emissions and Environmental Policy Trends**, including assessment of diverse portfolio options under the EPA GHG rule for fossil-fueled resources and NIPSCO's goal to achieve Net Zero carbon emissions by 2040
- **Flexibility & Adaptability of the Portfolio** to meet potential new sources of load growth in the NIPSCO territory while still planning to meet the needs of all NIPSCO customers

Using in-depth data, modeling, and risk-based analysis provided by internal and external subject matter experts, NIPSCO's IRP projects future energy and capacity needs and evaluates available options to meet those needs.

NIPSCO's 2024 IRP is based on the best available information at the time this IRP is submitted. Changes that affect our plan may arise, which is why it's important for us to remain flexible and adaptable as we continually evaluate current market conditions, the evolution of technology - particularly energy storage, carbon capture, utilization, and sequestration (CCUS), and hydrogen-based technology - and demand side resources, as well as changing local and federal laws and environmental regulations.



ENGAGE CUSTOMER AND PUBLIC STAKEHOLDERS

Indiana's energy future is everyone's concern. That's why any discussion of resource planning for the future must invite stakeholders into the conversation. We engaged stakeholder groups and individuals in a variety of ways throughout the entirety of the planning process.

NIPSCO initiated stakeholder advisory outreach for its 2024 IRP in April when we hosted a public meeting at Fair Oaks Farm in Fair Oaks, Indiana. Four additional public meetings followed in June, August, and October (2), each one hosted in-person with a virtual participation option as well. NIPSCO also hosted additional virtual technical webinar workshops to discuss IRP topics in greater detail with interested stakeholders. Each of the public stakeholder meetings had over 100 registered participants and garnered a high level of stakeholder participation. Members of NIPSCO's executive leadership team and several of our subject matter experts attended each meeting to hear feedback and answer questions.

Throughout the IRP process, stakeholders were also invited to meet with us on a one-on-one basis to discuss key concerns and perspectives. NIPSCO met with several stakeholders in virtual one-on-one settings and exchanged written correspondence with several others. Each interaction provided a forum for discussion and feedback related to the many components of the IRP. Valuable discussions arose in several key areas, including load forecasting calculations, energy efficiency program analysis, generation portfolio modeling techniques, and data centers.

Stakeholder feedback gained throughout the process was used to inform and improve the final plan. A summary of the meeting materials, including presentations and stakeholder questions, is available at **NIPSCO.com/IRP**.

FORECASTING FUTURE CUSTOMER DEMAND

Projecting customers' energy needs is a key component of the IRP process, and several enhancements to the development of the demand forecast were implemented in the 2024 IRP. The 2024 IRP undertook more rigorous analysis of Electric Vehicle (EV) and industrial loads, including potential new data center loads. A more robust analysis of demand-side management potential and programs was incorporated in the 2024 IRP as well. Grid-edge technologies such as electric vehicle charging, DER, and advanced metering infrastructure (AMI) were assessed to evaluate more responsive customer loads in the future.

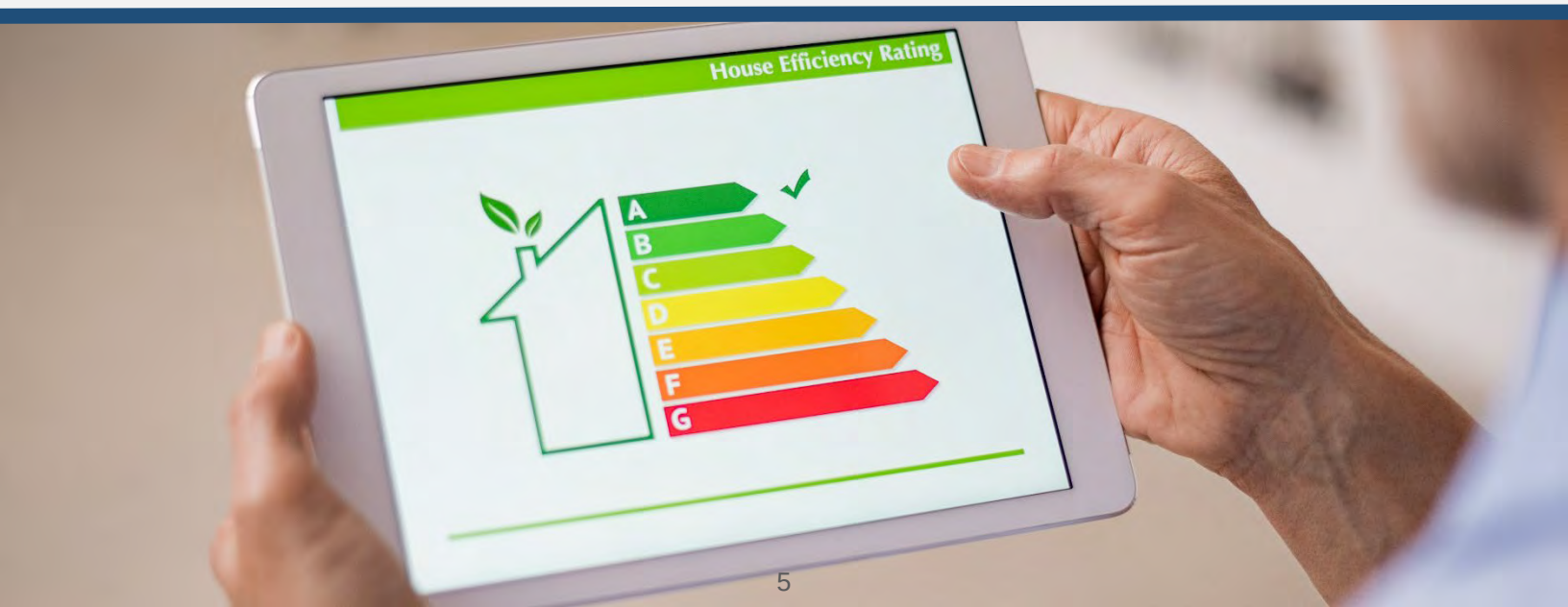
Leveraging NIPSCO's load forecasting tools, we developed monthly net energy and peak load projections to evaluate seasonal energy peak periods throughout the plan horizon. This was done through an econometric analysis of customer count, energy usage per customer, and customer class-level along with detailed analysis of the impact of changes in customer behavior on load requirements.

NIPSCO then forecasted the impact of customer-owned DER and EV on load across a range of adoption scenarios. NIPSCO's final forecasts combined the baseline econometric load projections with the DER and EV analysis across planning scenarios to capture a range of future load growth outcomes.

The anticipated growth in demand related to hyperscaler data centers is a new and rapidly changing opportunity in the NIPSCO service territory and across the broader utility industry. NIPSCO's analysis in the 2024 IRP was intended to provide initial guidance with the facts available at the time the core analysis was conducted. NIPSCO, however, will continue to monitor and evaluate the development of data center projects in the coming years. Further, NIPSCO will continue to refine its analysis of potential hyperscaler data center additions in future IRPs and other long-term portfolio planning analyses.

The Reference Case load forecast includes 600 MW of new demand attributable to hyperscaler data center projects beginning in 2028. To account for further data center and large industrial load growth over the IRP horizon, new demand attributable to large economic development projects rises to approximately 2,600 MW by 2035, approximately doubling NIPSCO's projected demand.

NIPSCO also included an Emerging Load sensitivity to account for increased data center demand beyond the Reference Case. This Emerging Load sensitivity projects an initial 3,200 MW of new demand attributable to data centers by 2028 and rising to 8,600 MW of new demand by 2035.



CURRENT SUPPLY

NIPSCO's resource portfolio is in the midst of a transition. NIPSCO continues with retirement activities at the R.M. Schahfer Generating Station. Schahfer Units 14 and 15 were retired in 2021, while Schahfer Coal Units 17 and 18 remain on track to retire by the end of 2025. To replace the retired capacity at Schahfer, the company continues to make progress on its 14 approved renewable energy projects, including wind, solar, and solar plus battery storage resources, as part of our "Your Energy, Your Future" transition plan. Two of these wind projects were placed in service in 2020. An additional wind project was placed into service in 2021. A fourth wind project as well as NIPSCO's first set of solar projects, were placed into service in 2023.

Due to supply chain constraints and price increases, several projects included in the 2021 IRP were either delayed or replaced with projects that were executable and more affordable for NIPSCO customers. NIPSCO's first solar plus battery storage project came online in 2024. The remaining seven projects, representing a mix of wind, solar, and storage, are expected to be completed throughout 2025. NIPSCO also expects a new Gas Peaking resource to come online by the end of 2027 to provide flexibility and reliability to customers and the system.

Additionally, NIPSCO's existing resource portfolio is composed of its last remaining coal-fired plant (Michigan City Unit 12),[2] two hydroelectric plants (Norway and Oakdale), a natural gas-fired combined cycle (Sugar Creek),[3] two older vintage natural gas-fired peaking units at Schahfer (Units 16A and 16B),[4] and demand-side management (DSM) resources.

As NIPSCO looks beyond the implementation of its short-term action plan from the 2021 IRP, it is clear that evolving market rules, environmental policies, and potential hyperscaler data center loads will require attention not only on annual supply and demand of capacity and energy, but also on energy adequacy on an hourly basis. Thus, the 2024 IRP was structured to ensure a robust assessment of the type of resources needed to respond to emerging market conditions and future portfolio retirements.

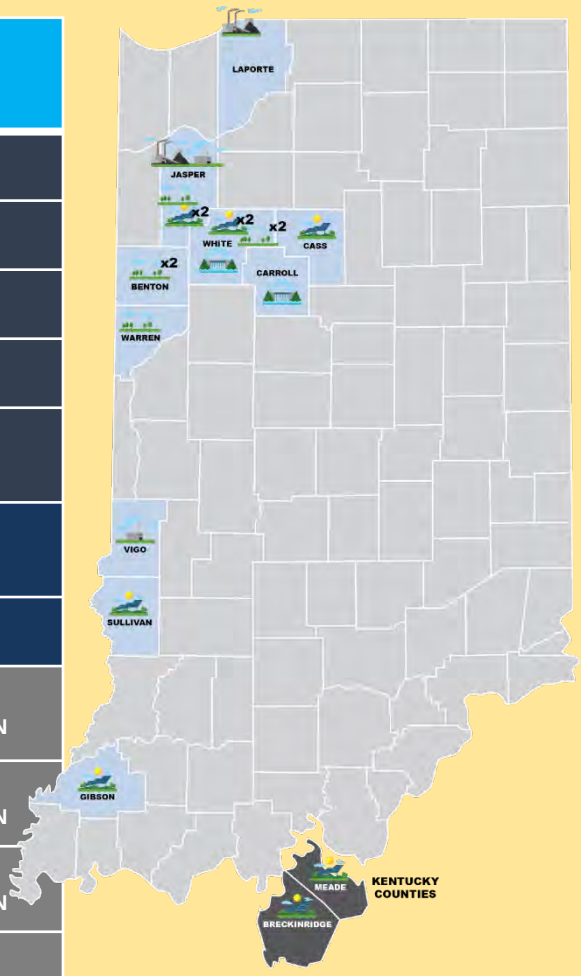


[2] Michigan City's Unit 12 is planned to retire by the end of 2028.
[3] Sugar Creek was recently uprated to capacity of 565 MW at the end of 2024.
[4] Expected to retire by the end of 2027.

CURRENT & FUTURE NIPSCO GENERATION PORTFOLIO

Robust Renewable Investments in Indiana

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
CAVALRY SOLAR	200 MW + 60 MW BATTERY	WHITE	2024 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE (KY)	2025 CONSTRUCTION
DUNNS BRIDGE SOLAR II	435 MW + 75 MW BATTERY	JASPER	2025 CONSTRUCTION
GIBSON SOLAR	200 MW	GIBSON	2025 CONSTRUCTION
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025 CONSTRUCTION
TEMPLETON WIND	200 MW	BENTON	2025 PRE-CONSTRUCTION
CARPENTER WIND	200 MW	JASPER	2025 PRE-CONSTRUCTION
APPLESEED SOLAR	200 MW	CASS	2025 PRE-CONSTRUCTION
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PRE-CONSTRUCTION



GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2025 (COAL) – 2028 (NG)	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	563 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL



ANALYZING FUTURE SUPPLY OPTIONS – REQUESTS FOR PROPOSALS

NIPSCO conducted four separate Request for Proposals (RFP) events covering all sources to help inform the 2024 IRP planning process and to gain information on available, actionable projects with real costs from the marketplace. All energy technology companies were eligible to participate, and for the 2024 RFP, NIPSCO received 116 proposals — representing 58 individual projects with more than 9.6 gigawatts (GW) of installed capacity (ICAP). In concert with the core IRP analysis, RFP screening criteria included energy source availability, technical feasibility, commercial availability, economic attractiveness, and environmental compatibility. NIPSCO is likely to conduct additional RFPs should hyperscaler data center opportunities materialize, to supplement the capacity sourced in the 2024 RFP. NIPSCO will also ensure full evaluation of a wide range of new technologies either via the RFP process or through other means such as pilots at existing facilities (i.e., Carbon Capture, Utilization, and Sequestration (CCUS) and hydrogen at Sugar Creek), LDES, and Small Modular Reactors (SMR), among other potential future technologies.

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY

DSM programs and energy efficiency measures have been an integral part of the NIPSCO supply mix. Promoting energy efficiency is not only good for customers, but it can also play an important role in helping ensure that we can meet future energy needs. Consequently, the assessment of DSM and energy efficiency programs is a core component of the IRP process.

NIPSCO offers a variety of programs to help residential and business customers conserve energy and save money. The programs are tailored to customers and designed to help ensure energy savings. From 2010 through June 2024, NIPSCO customers have saved more than 1.7 million megawatt hours of electricity by participating in the range of energy efficiency programs offered by NIPSCO.

Technologies continue to change, and it’s important that we constantly evaluate our offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings. The 2024 IRP included a robust assessment of future DSM programs through a Market Potential Study and rigorous portfolio analysis of the various options.

PREFERRED PORTFOLIO AND NEXT STEPS

NIPSCO has developed a short-term action plan in this 2024 IRP that ensures NIPSCO can confidently provide the least cost portfolio available while complying with significant regulatory changes from MISO in 2024. The short-term action plan ensures NIPSCO can maintain reliability, diversity, and flexibility regardless of whether or not new large loads come onto our system. Therefore, the action plan will cover needed actions and investments regardless of the level of load growth, and separately, other investments that will be contingent on large load growth (particularly from data center customers).

As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2025 and continue activities associated with the implementation of transmission system reliability upgrades. NIPSCO will also continue in its plan to retire Michigan City Unit 12 by 2028. NIPSCO will continue to complete and place in service wind, solar, and solar plus storage replacement resources previously approved by the Commission for the scheduled 2025 retirement of all coal units at Schahfer, and the scheduled 2028 retirement of Michigan City. A total of ~2,100 MW have been approved by the Commission and will be placed in-service between now and 2028: ~1,700 of renewable projects and the 400 MW gas peaker. Additionally, NIPSCO's two vintage gas peaking units (Schahfer 16A/B) will also retire in 2027, with the addition of the previously planned gas peaker at the Schahfer site.

Given the uncertainty around the timing and amount of hyperscaler data center load that may come onto NIPSCO's system, NIPSCO has a preferred plan that lays out two sets of new resource additions: The first set of resource additions will be added to the portfolio regardless of the size and timing of new hyperscaler data load on the system, and the second set of resource additions will only be added after hyperscaler data center load is contracted.

The first set of resource additions include short-term purchase power agreements (PPA) in the near term through 2029, along with significant amounts of new storage resources primarily over the next five years to provide needed accredited capacity under MISO's new D-LOL market design rule. To ensure compliance with MISO's D-LOL capacity accreditation rule that was approved by FERC in October 2024, NIPSCO will plan to add between 900 and 1,150 MW of new storage capacity and 350 MW of short-term thermal PPAs by 2028-2029. This will ensure we meet the peak load capacity requirements needed as the capacity accreditation of our existing and planned renewable assets decline under the D-LOL rule. NIPSCO will continue to track accreditation trends as the rule is implemented and adjust its storage procurement plan accordingly.



NIPSCO's plan also calls for 440 MW of combined Demand-Side Management resources to be implemented beginning in 2027 (both energy efficiency and demand response resources). In the mid-term and long-term, the preferred plan then includes additional storage resources and new wind resources to provide needed energy in the latter part of the IRP horizon. To continue progress towards NIPSCO's goal to achieve Net Zero for Scope 1 and Scope 2 CO2 emissions by 2040, the plan also projects a retrofit for Sugar Creek Generation Station to be powered by hydrogen after 2035.

The second set of resource additions will be contingent on contracting hyperscaler data center load. These include new combined cycle gas turbine (CCGT) resources that match the load needs of hyperscaler customers. These resources may be sourced from PPAs, build transfer agreements (BTAs), self-build projects, or some combination of those types. The preferred plan also includes flexible plans for additional capacity to be met by natural gas peaking resources if needed in preparation for the EPA's GHG rule, which will limit CCGT capacity factors to 40% in 2032 and beyond. Over the longer term, additional solar and wind capacity may be added if environmental policy continues to restrict gas-fired generation output and provide the needed tax credits for renewables to be economic. All new combined cycle gas resources will then plan for decarbonization retrofits in the latter half of the IRP to continue our pathway to Net Zero by 2040. The plan allows for flexibility in determining how these assets are decarbonized, and NIPSCO will continue to evaluate the most cost-effective methodology for decarbonizing the new facilities as technologies mature and costs change. Additional storage capacity may be added as further technology, policy, and reliability diligence is performed.

NIPSCO's 2024 IRP outlines refinements to the timeline of our future generation plans, and it enables flexibility to adapt to evolving technologies, policies, and market rules while providing additional time for research and further refinement to our long-term energy strategy. NIPSCO will continue to update its future energy strategy in the next IRP. More information about NIPSCO's electric supply strategies and the IRP process can be found at **NIPSCO.com/IRP**.

ACTION PLANS

NEAR-TERM ACTIONS (2025-2029)	

ACTION OVERVIEW	• Complete and place previously planned resource additions:
	  • 1,700 MW renewables
	  • 400 MW gas peaker
	• Complete retirement and shutdown of remaining Schahfer coal units (17, 18) by 2025 and Schahfer gas units (16A, 16B) by 2027
	• Complete retirement of Michigan City Unit 12 by 2028
	• Implement two sets of new resource resources additions:
	  • To meet the existing portfolio capacity needs by 2029 with short-term thermal contracts and battery storage
	  • To meet hyperscaler data center load with new gas CCGT and peaking resources
	• Implement new demand-side management programs in 2027 for energy efficiency and demand response
	• Actively monitor changing federal/state policy, MISO market rules, and technology advancements
	• Optimize exact quantities and resource types of portfolio additions

RETIREMENTS	• Schahfer Units 17, 18 (by 2025) • Schahfer Units 16A/B (by 2027) • Michigan City Unit 12 (by 2028)

NEW RESOURCE ADDITIONS – ABOVE IURC APPROVED PROJECTS	1. Resources planned for legacy portfolio load and any new hyperscaler data load:
	  • Storage (900+MW)*
	  • Thermal Contracts (150-350 MW)*
	  • DSM Resources (Energy Efficiency + Demand Response) (440 MW)*
	  • NIPSCO-owned DER (up to 20MW)*
	2. Resources planned only if new hyperscaler data center load is contracted (IRP assumes 2,600 MW of new load in total, with 600 MW of that total by 2028, and 1,600 by 2030):
	  • Gas CCGT (1,285 MW)
	  • Gas Peaking (420 MW)

MID-TERM ACTIONS (2030-2034)	

ACTION OVERVIEW	• Continue with two sets of new resource resources additions:
	  • To meet the existing portfolio energy and capacity needs with any additional wind and storage resources
	  • To meet hyperscaler data center load with new gas CCGT and peaking resources, supplemented with solar and wind resources if energy needs arise
	• Reevaluate decarbonization options including CCUS, H2, and other emerging technologies for best fit to decarbonize Sugar Creek and any additional gas resources brought online for hyperscaler data center load
	• Actively monitor changing federal/state policy, MISO market rules, and technology advancements
	• Optimize exact quantities and resource types of portfolio additions

RETIREMENTS	N/A

NEW RESOURCE ADDITIONS – ABOVE IURC APPROVED PROJECTS	1. Resources planned for legacy portfolio load and any new hyperscaler data load:
	  • Storage (125 MW)*
	  • Wind (150-650 MW)*
	2. 2Resources planned only if new hyperscaler data center load is contracted (IRP assumes 2,600 MW of new load in total by 2035):
	  • Gas CCGT (1,950 MW)
	  • Gas Peaking (200 MW)

* These resources are required for the portfolio even when evaluated without new data center load

ACTION PLANS

LONG-TERM ACTIONS (2035-2043)	

ACTION OVERVIEW	• Continue with two sets of new resource resources additions:
	  • To meet the existing portfolio energy and capacity needs with any additional wind and storage resources
	  • To meet hyperscaler data center load energy needs add additional solar capacity
	• Implement most cost-effective decarbonization retrofits to all gas CCGT units
	• Determine additional steps to achieve net zero
	• Optimize exact quantities and resource types of portfolio additions

RETIREMENTS	N/A

NEW RESOURCE ADDITIONS – ABOVE IURC APPROVED PROJECTS	1. Resources planned for legacy portfolio load and any new hyperscaler data load:
	  • Storage (25 MW)*
	  • Wind (200-900 MW)*
	  • Hydrogen retrofit at Sugar Creek Generating Station*
	2. Resources planned only if new hyperscaler data center load is contracted (IRP assumes 2,600 MW of new load in total):
	  • Solar (525 MW)
	  • Carbon capture retrofits on any new CCGT units

TIMING	NEAR TERM ACTIONS (2025-2029)	MID-TERM ACTION (2030-2034)	LONG TERM ACTIONS (BEYOND 2035)
RETIREMENTS	• Schahfer Units 17,18 (by 2025) • Schahfer Units 16A,16B (by 2027) • Michigan City Unit 12 (by 2028)	• N/A	• N/A
PREFERRED PLAN – CAPACITY ADDITIONS	• Storage (900+MW)* • Thermal Contracts (150-350MW)* • DSM Resources (Up to 440MW over 20 Year Period)* 2600MW DATA CENTER LOAD • Gas CCGT (1,285MW) • Gas Peaking (420MW)	• Storage (125MW)* • Wind (150-650MW)* 2600MW DATA CENTER LOAD • Solar (750MW) • Gas CCGT (1,950MW) • Gas Peaking (200MW)	• Storage (25MW)* • Wind (250-900MW)* • Sugar Creek Retrofit – Hydrogen* 2600MW DATA CENTER LOAD • Solar (525MW) • CCGT Retrofits - CCUS

OTHER ACTIVITIES	• Monitor changing regulatory policy (MISO, EPA, local) and technology advancements
	• Previously planned additions:
	  • 1,700MW Renewables
	  • 400MW Gas Peaker
		• Reevaluate decarbonization options including CCUS, H2 and other emerging technologies for best fit
		• Add additional renewables as needed to support higher energy needs
			• Implement most cost-effectives retrofits
			• Determine final steps to achieve Net Zero

STORAGE INVESTMENT	CCGT/GAS PEAKING INVESTMENT	MONITOR/RESPOND TO CHANGES	EXECUTE PREVIOUSLY PLANNED ACTIVITIES
~900MW of storage dependent on file MISO capacity accreditation	CCGT additions to support data center load and gas peaking investment as needed for additional capacity	MISO rules; EPA rules; Long-duration energy storage; Hydrogen; Carbon capture; Nuclear	Schahfer & Michigan City retirements; Renewable Projects ~1,700MW, ~400MW Gas Peaker

* These resources are required for the portfolio even when evaluated without new data center load



Northern Indiana Public Service Company LLC

2024
Integrated Resource Plan

December 9, 2024

Table of Contents

Section 1. Integrated Resource Plan Summary 1
1.1 Short-Term Action Plan 1
1.2 Plan Summary 4
1.3 Emerging Issues 5
1.3.1 Market Rules Uncertainty 5
1.3.2 Policy Uncertainty 6
1.3.3 Technology Uncertainty 6
Section 2. Planning for the Future 8
2.1 IRP Public Advisory Process 8
2.1.1 Stakeholder Meeting 1 8
2.1.2 Stakeholder Meeting 2 9
2.1.3 Stakeholder Meeting 3 10
2.1.4 Stakeholder Meeting 4 10
2.1.5 Stakeholder Meeting 5 10
2.2 Other Stakeholder Input Since NIPSCO's Last IRP 11
2.2.1 IURC Contemporary Issues 11
2.2.2 2021 IRP Feedback and 2024 Process Improvement Efforts 12
2.2.3 Equitable Transition 13
2.3 Overall IRP Approach 13
2.3.1 Step 1: Identify Planning Objectives and Key Questions 16
2.3.2 Step 2: Develop Market Perspectives 21
2.3.3 Step 3: Develop Integrated Resource Strategies 25
2.3.4 Step 4: Portfolio Modeling 27
2.3.5 Step 5: Evaluate Tradeoffs and Produce Recommendations 27
Section 3. Energy and Demand Forecast 28
3.1 Introduction and Major Highlights of the Forecast 28
3.2 Forecasting Methodology Overview 29
3.3 Base Customer Count, Electric Energy, and Peak Demand Forecast 30
3.3.1 Data Gathering, Weather Normalization, and Econometric Modeling 30

3.3.2 Industrial Service Structure....34
3.3.3 Customer Count Forecast....34
3.3.4 Sales per Customer and Total Electric Sales Forecast....36
3.3.5 Peak Load Forecast Development....37
3.4 Electric Vehicles....39
3.4.1 Methodology Overview....39
3.4.2 Core Data Source Inputs....39
3.4.3 Light Duty Vehicles....40
3.4.4 MDV and Transit Vehicles....50
3.4.5 Heavy-Duty Vehicles....57
3.4.6 Corridor Charging....57
3.4.7 Electric Vehicle Forecast Results....65
3.5 Customer-Owned DERs....67
3.5.1 Existing Solar Distributed Energy Resources....67
3.5.2 Customer-Owned Distributed Energy Resource Projections....71
3.5.3 Key Input Assumptions....72
3.6 Large Economic Development Loads....79
3.7 All-in Load Summary....81
3.8 Scenario Analysis....83
3.8.1 Economic Variables....84
3.8.2 Electric Vehicles....84
3.8.3 Distributed Energy Resources....84
3.8.4 Other Electrification....84
3.8.5 Industrial Load Risk....85
3.8.6 Conversion from Sales to Peak....86
3.8.7 Scenario Results....87
3.9 Detailed Forecast Results....89
Section 4. Supply-Side Resources....102
4.1 Existing Resources....102
4.1.1 Michigan City....103
4.1.2 Schahfer....103
4.1.3 Sugar Creek....104

4.1.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources)....105
4.1.5 NIPSCO Wind and Solar Purchase Power Agreements and Joint Venture....106
4.1.6 Total Resource Summary....109
4.2 Fuel, Energy, and Capacity Procurement Strategy for Existing Resources 110
4.2.1 Coal Procurement and Inventory Management Practices....110
4.2.2 Natural Gas Procurement and Management....114
4.2.3 Electric Generation Gas Supply Request for Proposal Process....115
4.3 Planned Resource Summary....115
4.3.1 Planned Wind Resources....115
4.3.2 Planned Solar and Solar + Storage Resources....116
4.4 MISO Wholesale Electricity Market....119
4.4.1 Operations Management and Dispatch Implications....119
4.5 Resource Adequacy and Current Supply-Demand Balance....119
4.6 Future Resource Options....120
4.6.1 Request for Proposal....121
4.6.2 Incorporation of the RFP Results into the IRP....125
4.6.3 Longer-Term New Resource Assumptions – Mature Technologies....128
4.6.4 Emerging Technologies – Hydrogen....131
4.6.5 Emerging Technologies – Renewable Natural Gas....136
4.6.6 Emerging Technologies – Carbon Capture, Utilization, and Storage....136
4.6.7 Emerging Technologies – Long-Duration Energy Storage....142
4.6.8 Emerging Technologies – Small Modular Reactors....147
4.6.9 Long-Term Uncertainties with Emerging Technologies....152
4.6.10 Federal Tax Incentives for Clean Energy Resources....152
Section 5. Demand-Side Resources....155
5.1 Existing Resources....155
5.1.1 Existing Energy Efficiency Resources....155
5.1.2 Existing Demand Response Resources....165
5.2 DSM MPS....165

5.2.1 DSM MPS – Purpose and Key Objectives 165
5.2.2 Impact of Opt-out Customers.....166
5.2.3 Modeling Framework.....166
5.2.4 Key Assumptions That Impact Energy Efficiency Potential 166
5.2.5 Energy Efficiency Measures & Potential.....168
5.2.6 DR Potential.....175
5.3 Future Resource Options.....178
5.3.1 Energy Efficiency Bundles 178
5.3.2 DR Programs.....192
5.4 Consistency between IRP and Energy Efficiency Plans.....194
Section 6. Transmission and Distribution System.....196
6.1 Transmission System Planning 196
6.1.1 Transmission System Planning Criteria and Guidelines.....196
6.1.2 North American Electric Reliability Corporation.....196
6.1.3 Midcontinent Independent System Operator, Inc. 197
6.1.4 Market Participants 198
6.1.5 Customer Driven Development Projects 198
6.1.6 NIPSCO Transmission System Capital Projects.....198
6.1.7 Electric Infrastructure Modernization Plan.....199
6.2 Distribution System Planning 199
6.2.1 Evolving Technologies and System Capabilities.....201
Section 7. Environmental Considerations 203
7.1 Environmental Sustainability.....203
203
7.2 Environmental Compliance Plan Development.....203
7.3 Environmental Regulations.....204
7.3.1 Solid Waste Management 204
7.3.2 Clean Water Act and Effluent Limitations Guidelines (ELG).....204
7.3.3 Clean Air Act 204
7.4 Climate-Related Considerations 205
Section 8. Managing Risk and Uncertainty.....206
8.1 Introduction & Process Overview.....206

8.2 Reference Case Market Drivers and Assumptions 207
8.2.1 Natural Gas Prices....207
8.2.2 Coal Prices 213
8.2.3 Carbon Emission Regulation 215
8.2.4 MISO Energy and Capacity Prices 216
8.3 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment....221
8.4 IRP Scenarios....223
8.4.1 Scenario Overview....223
8.4.2 Slower Transition Scenario....224
8.4.3 Domestic Resiliency Scenario 226
8.4.4 Aggressive Environmental Regulation Scenario 228
8.4.5 Accelerated Innovation Scenario 231
8.4.6 Scenario Comparisons 233
8.5 Stochastic Modeling and Analysis....241
8.5.1 Stochastic Analysis Motivation and Key Metrics....241
8.5.2 Stochastic Modeling Approach....242
8.5.3 Input Data Development....242
8.5.4 Statistical and Fundamental Analysis 244
Section 9. Portfolio Analysis....250
9.1 Portfolio Development....250
9.1.1 Process Overview....250
9.1.2 Portfolio Concepts 250
9.1.3 Portfolio Optimization Analysis 251
9.1.4 Additional Portfolio Variants....256
9.1.5 DSM Program Selection 258
9.2 Portfolio Evaluation – Scorecard Metrics....260
9.3 Portfolio Evaluation – Analysis Results 261
9.3.1 Reference Case Customer Cost Results....261
9.3.2 Scenario Customer Cost Results....262
9.3.3 Stochastic Analysis Results 267
9.3.4 CO2 Emissions....272
9.3.5 Sensitivity Analysis – Flat Load Growth....275

9.3.6 Sensitivity Analysis – Emerging High Load Growth 279
9.3.1 Sensitivity Analysis – Additional DSM.....281
9.3.2 Scorecard Summary 282
9.4 Preferred Portfolio 284
9.4.1 Preferred Portfolio Summary.....288
9.4.2 Financial Impact.....289
9.4.3 Developments That Will Shape NIPSCO's Preferred Portfolio Implementation 290
9.5 Short-Term Action Plan.....292
9.6 Conclusion 292
Section 10. Customer Engagement 294
10.1 Enhancing Customer Engagement.....294
10.1.1 Leveraging Customer and Stakeholder Feedback.....294
10.1.2 Customer Education – Generation Transition, Energy Efficiency and Assistance 296
10.2 Community Partnerships.....298
10.2.1 Community Advisory Panels 298
10.3 Customer Programs.....298
10.3.1 Feed-in Tariff (FIT) 298
10.3.2 Excess Distributed Generation Tariff 300
10.3.3 Green Power Rider (GPR) Program 301
10.3.4 Green Path Rider Program.....303
10.3.5 Transportation Decarbonization: DC Fast charging stations & IDEM Grant 304
10.3.6 Advanced Metering Infrastructure (AMI) 304
10.3.7 Supporting Economic Growth 305
10.3.8 Supplier Diversity 305
10.3.9 Workforce Development.....305
10.3.10 Corporate Citizenship 308
10.3.11 Targeted Grants.....308
10.3.12 Charitable Giving.....309
Section 11. Compliance with IRP Rule.....311

ACRONYMS AND ABBREVIATIONS

A

AC	Air Conditioning
ACS	American Community Survey 2022
AEO	Annual Energy Outlook (from EIA)
AER	Aggressive Environmental Regulation scenario
AGP	Advanced Gas Path
AI	Accelerated Innovation scenario
ASHP	Air Source Heat Pumps
AMI	Advanced Metering Infrastructure
ATC	Around-the-Clock

B

BECCS	Biomass Energy Carbon Capture and Storage
BEV	Battery Electric Vehicles
BIL	Bipartisan Infrastructure Law
BTAs	Build transfer agreements
BTM	Behind-the-meter
BMV	Bureau of Motor Vehicles
BWR	Boiling Water Reactors

C

C&I	Commercial and Industrial
CAES	Compressed air energy storage
CAGR	Compound Annual Growth Rate
CapEx	Capital Expenditures
CAP	Community Advisory Panel
CAPP	Central Appalachia
CATF	Clean Air Task Force
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Sequestration
CDD	Cooling Degree Days
CES	Chemical energy storage
CF	Capacity Factor
CO	Carbon Monixide
CO2	Carbon Dioxide
CO/UT	Colorado/Utah Basin

Company	Northern Indiana Public Service Company LLC
CPCN	Certificate of Public Convenience and Necessity
CRA	Charles River Associates (IRP Consultant)
CT	Combustion Turbine
CWA	Clean Water Act

D

DA	Distribution Automation
DER	Distributed Energy Resource
DG	Distributed Generation
DG Statute	Indiana Code Ch. 8-1-40
D-LOL	Direct Loss of Load
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
DR	Demand Response
DRR1	Demand Resource Type 1
DRS	Domestic Resiliency Scenario
DSM	Demand-Side Management
DSM Statute	Ind. Code § 8-1-8.5-10

E

EDG	Excess Distributed Generation
EDR	Emergency Demand Response
EE	Energy Efficiency
EES	Electrochemical energy storage
EGU	Electric Generating Unit
EIA	Energy Information Administration of the U.S. Department of Energy
ELCC	Effective Load Carrying Capability
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ESOP	Energy Storage Operations
ESR	Electric Storage Resources
EUE	Expected Unserved Energy
EV	Electric Vehicles

F

FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

FOB	Free Over Board

G

GDS	GDS Associates, Inc.
GDS Team	GDS and Demand Side Analytics
GHG	Green House Gas
GHG Rules	GHG Standards and Guidelines
GPCM	Gas Pipeline Competition Model
GPR	Green Power Rider
GW	Gigawatt
GWh	Gigawatt-hour

H

H2	Hydrogen
HALEU	High-Assay, Low-Enriched Uranium
HDD	Heating Degree Days
HDV	Heavy-Duty Vehicle
Hg	Mercury
HPMS	Highway Performance Monitoring System
HRSG	Heat Recovery Steam Generator
HSPF	Heating Seasonal Performance Factor
HTGCR	High-Temperature Gas-Cooled Reactor
HVAC	Heating, Ventilation, and Air Conditioning

I

ICAP	Installed Capacity
ICE	Internal Combustion Engine
IDEM	Indiana Department of Environmental Management
IEDC	Indiana Economic Development Corporation
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IFSA	Indiana Solar For All coalition
IGCC	Integrated Gas Combined Cycle
ILB	Illinois Basin
IMEP	Interregional Market Efficiency Project
INDOT	Indiana Department of Transportation
IRA	Inflation Reduction Act
IRP	Integrated Resource Planning
IRP Rule	170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans
ISO	Independent System Operator

ISP	Investment Tax Credit
ITC	Integrated System Planning
IURC/Commission	Indiana Utility Regulatory Commission

J

JA	Junior Achievement
JOA	Joint Operating Agreement

K

kWh	Kilowatt hour

L

LAES	Liquid Air Energy Storage
LDES	Long-Duration Energy Storage
LDV	Light-Duty Passenger Vehicle
LED	Light Emitting Diode
LEU	Low-Enriched Uranium
LHS	Latent Heat Storage
LLF	Line Loss Factors
LMR	Load Modifying Resource
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LRZ 6	MISO Load Resource Zone 6

M

MAP	Maximum Achievable Potential
MDV	Medium-Duty Vehicle
MES	Mechanical Energy Storage
Michigan City	Michigan City Generating Station
Michigan City 12	Michigan City Unit 12
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Metric Million British Thermal Unit
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Planning
MT	Million Tons
MTEP	MISO Transmission Expansion Plan
MTPA	Million Tons Per Annum
MW	Megawatt

MWh	Megawatt-hour

N

NAPP	Northern Appalachian
NDC	Net Demonstrated Capacity
NERC	North American Electric Reliability Corporation (formerly Council)
NETL	National Energy Technology Laboratory
NEVI	National Electric Vehicle Infrastructure
NG	Natural Gas
NGF	CRA's Natural Gas Fundamentals Market Model
NIPSCO	Northern Indiana Public Service Company LLC
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPP	Nuclear Power Plant
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NSRDB	National Solar Radiation Database
NREL	National Renewable Energy Laboratory
NTD	National Transportation Database
NTG	Net To Gross
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance
OFA	Over-Fire Air
OSB	Energy Efficiency Oversight Board
OUCC	Indiana Office of Utility Consumer Counselor

P

PEC	Polyethylene Carbonates
PenDER	CRA's DER Penetration Model
PEV	Plug-In Electric Vehicle
PGC	Potential Gas Committee
PHEV	Plug-In Hybrid Electric Vehicle
PHS	Pumped Hydro Storage
PJM	PJM LLC (Regional Transmission Organization)
PPA	Purchase Power Agreement
PPC	Polypropylene Carbonate
PRB	Powder River Basin
PRMR	MISO's Planning Reserve Margin Requirement

PTC	Production Tax Credit
PV	Photovoltaic
OWR	Pressurized Water Reactor

R

RAP	Realistic Achievable Potential
RBDC	Reliability Based Demand Curve
RCRA	Resource Conservation and Recovery Act
RCx	Retro-Commissioning
REC	Renewable Energy Credit
REF	Reference Case Scenario
RFP/2024 RFP	Request for Proposals/2024RFP Events
RIIA	Renewable Integration Impact Assessment
RIM	Rate Payer Impact Measure
RNG	Renewable natural gas
RPPA	Renewable Purchase Power Agreement
RTE	Round-trip efficiencies
RTO	Regional Transmission Organization (Independent System Operator)

S

SAIFI	System Average Interruption Frequency Index (Reliability-SAIDI and CAIDI)
SAM	System Advisor Model
SCADA	Supervisory Control and Data Acquisition
Schahfer	R.M. Schahfer Generating Station
SEER	Seasonal Energy Efficiency Ratio
SHS	Sensible Heat Storage
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
SOC	State of Charge
SO2	Sulfur Dioxide
ST	Slower Transition scenario
STEM	Science, Technology, Engineering, and Math
Sugar Creek	Sugar Creek Generating Station

T

T&D	Transmission and Distribution
Tcf	Trillion cubic feet
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
TES	Thermal Energy Storage
THS	Thermochemical Heat Storage

TRC	TRC Companies, Inc.
TRL	Technology Readiness Level
TRM	Technical Resource Manual
TW	Terawatt
TWh	Terawatt-hours

U

UCAP	Unforced Capacity (the amount of Installed Capacity actually available)
UCCI	Upstream Cost of Capital Index
UCT	Utility Cost Test

V

VOM	Variable Operations and Maintenance Costs

W

WACC	Weighted Average Cost of Capital

Z

ZRCs	Zonal Resource Credits

Section 1. Integrated Resource Plan Summary

1.1 Short-Term Action Plan

NIPSCO has developed a short-term action plan in this 2024 IRP that ensures NIPSCO can confidently provide a portfolio that best balances cost to customers while complying with significant regulatory changes from MISO in 2024. The short-term action plan ensures NIPSCO can maintain reliability, diversity, and flexibility regardless of whether or not new large loads come onto our system from data centers. Therefore, the action plan will cover needed actions and investments regardless of the level of load growth, and separately, other investments that will be contingent on large load growth (particularly from data center customers).

As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2025 and continue activities associated with the implementation of transmission system reliability upgrades. NIPSCO will also continue in its plan to retire Michigan City Unit 12 by 2028. NIPSCO will continue to complete and place in service wind, solar, and solar plus storage replacement resources previously approved by the Commission for the scheduled 2025 retirement of all coal units at Schahfer, and the scheduled 2028 retirement of Michigan City. A total of ~2,100 MW have been approved by the Commission and will be placed in-service between now and 2028: ~1,700 of renewable projects and the 400 MW gas peaker. Additionally, NIPSCO's two vintage gas peaking units (Schahfer 16A/B) will also retire in 2027, with the addition of the previously planned gas peaker at the Schahfer site.

In order to ensure compliance with MISO's D-LOL capacity accreditation rule that was approved by FERC in October 2024, NIPSCO will plan to add between 900 and 1,150 MW of new storage capacity and 350 MW of short-term thermal PPAs by 2028-2029. This will ensure we meet the peak load capacity requirements needed as the capacity accreditation of our existing and planned renewable assets decline under the D-LOL rule. NIPSCO will monitor accreditation metrics under the D-LOL rule and adjust its storage procurement plan as needed over time.

In addition, if new large load data centers are contracted, NIPSCO currently is prepared to meet these capacity and energy needs with an equivalent amount of installed capacity from CCGTs. These resources may be sourced from PPAs, BTAs, self-build projects, or some combination of those types. NIPSCO will also prepare plans for additional gas peaking resources if data center load is contracted, in order to supplement the previously mentioned CCGT resources, should the EPA's GHG rule limit CCGT capacity factors to 40% in 2032 and beyond.

The robust response to the 2024 RFPs (discussed in more detail in Section 4) indicates that there is a diverse set of resources and projects to meet NIPSCO supply needs over the near term, particularly with storage. NIPSCO will select projects/bids through the 2024 RFP's evaluation process, prioritizing cost-effective dispatchable resources that can be implemented before the D-LOL rule goes into effect in 2028, including storage and thermal contracts. NIPSCO will also engage with bidders on emerging technology resources, such as long-duration energy storage and hydrogen technologies, to pursue pilots and inform how such technologies can be deployed by NIPSCO to achieve further decarbonization of the generation portfolio over the long term.

Additionally, NIPSCO will implement NIPSCO-owned DER opportunities over the next five years to support the energy needs of local communities, as well as look to partner with recipients of federal solar grants in implementing their programs in our service territory.

NIPSCO will make the necessary regulatory filings with the Commission and continue to monitor federal and state policy, MISO market trends, and emerging technologies while staying actively engaged with project developers and asset owners to maintain flexibility and optionality. If necessary, NIPSCO may conduct future RFPs to identify additional resources to support large load growth and decarbonization.

Lastly, NIPSCO will continue to invest and modernize its electric infrastructure to maintain the safe and reliable delivery of electricity to its customers.

As described in greater detail in Section 9, the action items included in NIPSCO's short-term action plan include those listed in Table 1-1.

Table 1-1: 2024 IRP Short-Term Action Plan

Complete and place in service the remaining renewable facilities and gas peaker project approved by the IURC but not yet operational
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by the end of 2025
Complete the retirement of Michigan City 12 by the end of 2028
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Continue implementation of filed DSM Plan for 2025 through 2026
Select the best storage projects from the 2024 RFP, optimizing existing interconnection rights and federal tax credit opportunities
Procure short-term capacity as needed from the 2024 RFP, the MISO market, or through short-term bilateral capacity transactions
Continue discussions with new data center customers and refine the near- to mid-term load outlook as contracts are signed and expected loads are firmed
Perform additional diligence on the costs, feasible locations, and operational characteristics of new natural gas combined cycle and peaking additions necessary to meet any new data center load
Study potential future decarbonization pathways for gas-fired generation further, particularly CCUS and hydrogen blending
As needed, conduct a subsequent RFP(s) to identify additional resources that may be available with attributes that are consistent with those required to implement the preferred portfolio
Explore potential pilot projects from the RFP associated with emerging technologies, such as long-duration energy storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
Continue to actively monitor technology and MISO market trends while staying engaged with project developers and asset owners to understand landscape
Perform additional reliability analysis within the NIPSCO system as needed to ensure evolving portfolio meets all reliability needs and requirements
Comply with NERC, EPA, and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

1.2 Plan Summary

NIPSCO's preferred portfolio pathway preserves flexibility and our ability to adapt to potential changes in environmental regulations, federal and state energy policy, and other market forces while providing additional time for further research, refinement and confirmation of our long-term energy plans. The plan was developed to ensure that a reliable, compliant, flexible, diverse, and affordable supply will continue to be available to meet future customer needs. NIPSCO carefully planned and considered the impacts to its employees, the environment, and the local economy of the communities NIPSCO serves (property tax, supplier spend, employee base) as the plans were developed.

This preferred plan was developed through substantial quantitative and qualitative analyses that capture the ever-evolving energy landscape to allow NIPSCO to remain flexible in a time of uncertainty. NIPSCO utilized the 2024 RFP solicitations to identify the best combination of supply- and demand-side resources to meet its capacity needs.

The 2024 RFPs provided NIPSCO insight into the most relevant types of resources available to meet customer needs and their prices (*see* Section 4). NIPSCO performed its analysis using robust scenario and risk-based (stochastic) approaches that capture the flexibility and adaptability of the portfolio among changing market rules; environmental policy and regulations/incentives in an uncertain policy future; and system reliability implications of a portfolio with significant intermittent resources. NIPSCO also performed a probabilistic reliability assessment to understand the implications of potential resource additions to the NIPSCO portfolio and incorporated the results into the final scoring to create the optimal plan.

It is important to note that the IRP is a snapshot in time, and while it establishes a direction for NIPSCO, it is subject to change as the energy landscape continues to evolve. NIPSCO will continue to engage its stakeholders and be transparent in its decisions following submission of this 2024 IRP.

NIPSCO's supply strategy for the next 20 years is expected to:

- Phase out 100% of its coal generation by the end of 2028;
- Replace retired generation resources with a diverse, flexible, and scalable mix of planned resources, including short-term capacity contracts, large energy storage additions, and incremental long-term wind resources;
- Plan for new natural gas-fired generation, both CCGT and gas peaking resources, supplemented by solar and wind resources if new hyperscaler data centers are contracted;
- Seek to advance NIPSCO's knowledge and understanding of carbon capture and sequestration, hydrogen, and other emerging storage technologies identified as potential pathways toward further decarbonization of the generation portfolio in the long term;

- Remain on a pathway to achieve NiSource's Net Zero Goal for Scope 1 and Scope 2 greenhouse gas emissions by 2040; and

- Continue the Company's commitment to energy efficiency and demand response by executing DSM plans.

1.3 Emerging Issues

NIPSCO's preferred plan follows a supply strategy focused on compliance and reliability, with a mix of storage and new gas resources to support large load growth, as well as incremental renewable resources and market purchases in the mid-term. This provides the mobalanced plan that mitigates risk associated with changing capacity rules, policy, and technology uncertainty.

1.3.1 Market Rules Uncertainty

At the outset of its 2024 IRP process, NIPSCO identified several regulatory developments at the MISO level that could impact portfolio capacity accreditation. In 2023, MISO implemented a four-season capacity construct with obligations and resource accreditations varying by the four seasons across the MISO Planning Year. Previously capacity credit had focused on the summer peak. In 2025, MISO plans to implement a "downward sloping" reliability-based demand curve to value capacity across a range of reserve margin levels. And, during our IRP process, MISO filed for another capacity credit change for the 2028 planning year, the D-LOL market design which drives toward marginal capacity accreditation, with obligations and resource accreditations focused on performance during tight margin hours. This D-LOL market design was then approved by FERC in October 2024. This D-LOL market design is expected to have the following characteristics and impacts:

- Strong incentive to perform during hours when net load and outages are high;

- Resource accreditation based on LOLE assumptions based on historical class-level and unit-specific data;

- Capacity accreditations are expected to change, with MISO's indicative forward modeling currently projecting that:

    - The capacity credit of wind and solar resources will be significantly reduced across all four seasons;

    - The capacity credit of lithium ion battery storage will be reduced primarily in winter;

    - There will likely be a reduction in natural gas resource accreditation across all four seasons.

- Seasonal planning reserve margins are expected to decline, but NIPSCO's resource obligation during the summer is expected to grow by as much as ~500 MW due to

the reduction in capacity credit given to its current and planned renewable resources.

1.3.2 Policy Uncertainty

During the development of NIPSCO's 2024 IRP, the EPA finalized its Greenhouse Gas Rule in April 2024. This led to a preferred portfolio focused on compliance with the rule, and as a result included additional projected gas peaking and renewable resources to prepare for the rule's impacts in 2032 (additional information on all environmental issues can be found in Section 7). After the preferred plan was announced, the federal election results indicated a change to Republican control of the presidency and both houses of Congress. Given the policy leanings of the new administration and Congress, this may lead to further uncertainty for implementation of the EPA GHG rule, along with uncertainty in various provisions of the Inflation Reduction Act:

- The magnitude and eligibility period of the PTC and ITC for clean energy resources
- The potential development of the hydrogen economy, incentivized by the IRA's regional Hydrogen Hubs grants
- The enhancements to the 45Q tax credit which incentivized the use of CCUS

1.3.3 Technology Uncertainty

As the power sector continues to navigate a period of significant change, NIPSCO expects that technology evolution will be rapid, requiring regular review of the supply-side resource marketplace and flexibility in the preferred portfolio. Going forward, NIPSCO expects power sector technology evolution to continue to impact both short-term procurement activities and long-term resource decisions. In particular, NIPSCO will continue to monitor the following:

- Stand-alone storage resource costs, efficiencies, and operational parameters, such as cycle limits, depth of discharge specifications, and ongoing expenses;
- Long-duration storage technologies, including redox flow, metal air, compressed air, and other mechanical storage and their associated costs, efficiencies, and other value drivers;
- Hydrogen production developments and the costs and capabilities of turbines and other thermal resources to burn hydrogen or blend hydrogen with natural gas;
- CCUS costs and sequestration opportunities, particularly associated any new CCGT generation built for load growth;
- Other technologies that may emerge over the long term, including small modular reactors and other nuclear technology; and

- Grid-forming inverter technology that could provide reliability benefits, such as blackstart, fast frequency response, and inertial response, to NIPSCO's system as it becomes more inverter-based.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2024 IRP stakeholder process focused on continuing to increase transparency around its planning process and enhance public involvement through extensive stakeholder interactions. At each stakeholder meeting, NIPSCO provided information on the processes and assumptions involved in the development of the IRP and solicited relevant input for consideration. In addition, for the 2024 IRP, NIPSCO acquired Aurora model licenses for interested stakeholders and provided three separate model data releases to stakeholders as it performed and completed modeling analysis. The model releases were delivered after Stakeholder Meetings 3, 4, and 5, and included Aurora project and database files and accompanying data inputs and notes in Excel format. Furthermore, to facilitate stakeholder outreach and ongoing communications, NIPSCO maintained a web page on its website with current information about the IRP. NIPSCO posted all meeting agendas, presentations, meeting notes, and other relevant documents to the web page.

As part of the IRP process, NIPSCO conducted a RFP solicitation to identify the most viable resources currently available in the market to best meet customer needs. NIPSCO sought input from stakeholders regarding the approach and design of the All-Source RFP to ensure a robust and transparent process that yielded the desired results.

NIPSCO hosted five public advisory meetings with in-person and virtual attendance options as part of the 2024 IRP. For all meetings, NIPSCO posted an open invitation on its website for any party wishing to register. In addition to the public advisory meetings, NIPSCO participated in a number of additional technical workshop sessions with smaller groups of stakeholders to address specific concerns and issues that were raised as a result of information presented and discussed at the public advisory meetings. NIPSCO also corresponded with individual stakeholders on a variety of issues throughout the process. In the section that follows, NIPSCO provides an overview of its stakeholder process. A more comprehensive accounting of stakeholder meetings, presentations, and meeting notes is included in Appendix A.

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held at Fair Oaks Farm located in Fair Oaks, Indiana[1] (and virtually) on April 23, 2024. In this first meeting, NIPSCO set the stage for the 2024 IRP and outlined the fundamental pillars of NIPSCO's long-term resource planning strategy and how they align with the Five Pillars of long-term planning established by the Indiana 21st Century Energy Task Force. NIPSCO then provided an update on recent state, ISO, and federal policy developments, including capacity accreditation reforms at MISO and power sector GHG rules from the EPA. An update on the progress of the 2021 Short-Term Action Plan and the ongoing generation transition plan was also discussed.

[1] The in-person portion of all five stakeholder meetings was hosted at Fair Oaks Farm in Fair Oaks, IN.

Process improvements from the 2021 IRP were then discussed in detail, including improvements associated with the load forecast, demand-side management analysis, portfolio evaluation, and stakeholder collaboration. NIPSCO then provided an overview of its overall resource planning process, introduced its 2024 IRP scenarios, discussed its evolving stochastic analysis approach, and introduced its 2024 IRP scorecard. NIPSCO then provided an overview of its load forecast, including detailed projections for customer-owned distributed energy resource and electric vehicle growth.

NIPSCO then introduced its 2024 RFP, outlining the process, structure of RFP events, preliminary evaluation criteria, and timeline. Finally, NIPSCO concluded with the stakeholder advisory meeting road map for the remainder of the year. The meeting presentation (including the agenda), notes (including questions/responses), and registered participants for Meeting 1 are included in Appendix A.

2.1.2 Stakeholder Meeting 2

NIPSCO's second stakeholder meeting was held on June 24, 2024. In this second meeting, NIPSCO provided an overview of the resource planning process and provided an update on NIPSCO's response to stakeholder feedback received since the first meeting. Based on information that emerged between the first and second stakeholder meetings, NIPSCO then provided an update to its load forecast, with special attention given to significant new load growth now anticipated from large economic development loads, particularly data centers. The update included a new reference case load forecast and a high emerging load sensitivity. NIPSCO then provided an overview of all of its IRP load scenarios associated with uncertainty in economic growth, electric vehicle and distributed energy resource penetration, and long-term electrification. The electric vehicle review included forecasts of charging load on highway corridors. NIPSCO then provided a detailed review of its starting supply-demand position, particularly in light of MISO's D-LOL filing.

NIPSCO then introduced its fundamental market modeling structure and reviewed the Reference Case projections for fuel prices (natural gas and coal), environmental policy drivers, and MISO market dynamics, including MISO price forecasts. Each of the key variable drivers across each of NIPSCO's five planning scenarios was then reviewed. NIPSCO then provided a summary of the major stochastic variable inputs (renewable generator output, NIPSCO load, thermal resource outages, natural gas prices, and power prices) and summarized the stochastic analysis approach to measure reliability and cost risk.

Finally, NIPSCO provided a preliminary summary of the results of its RFP, including the number of proposals received, the types of projects offered, the location of the projects, and initial summaries of average pricing. The meeting presentation (including the agenda), stakeholder presentations, notes (including questions / responses), and registered participants for Meeting 2 are included in Appendix A.

2.1.3 Stakeholder Meeting 3

NIPSCO's third stakeholder meeting was held on August 21, 2024. In this third meeting, NIPSCO provided a recap of its revised Reference Case load forecast and its starting supply-demand balance. NIPSCO then shared an in-depth overview of DSM modeling, methodology, and how these resources are considered in the IRP. This included an overview of the market potential for energy efficiency, the various energy efficiency bundles, and the range of demand response program options to be evaluated in the 2024 IRP.

NIPSCO then reviewed the full set of resource options available for portfolio selection, including the details of the DSM bundles, detailed RFP tranche data, and the cost and operational assumptions for other generic new resource options, including eligible tax credits. NIPSCO closed the session with an overview of the portfolio construction framework and plan for full portfolio optimization and evaluation. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 3 are included in Appendix A.

2.1.4 Stakeholder Meeting 4

NIPSCO's fourth stakeholder meeting was held on October 8, 2024. In this fourth meeting, NIPSCO reviewed the overall IRP process and summarized responses to feedback and questions provided since the third stakeholder meeting. NIPSCO then reviewed its available new resource options and presented an overview of the portfolio construction framework, which developed six portfolio themes based on different constraints associated with MISO capacity accreditation rules and the emissions intensity of its portfolio.

NIPSCO then reviewed the results of its portfolio optimization analysis for each of the six portfolio themes. This included a review of the annual and total resource additions by type, seasonal supply-demand balances for all four MISO planning seasons, and projected energy positions. NIPSCO also presented the energy efficiency and demand response selections for all six portfolio themes and introduced two additional portfolio variants that contemplated retrofitting combined cycle capacity with carbon capture, utilization, and storage capability or the ability to blend hydrogen fuel. NIPSCO closed the presentation with a summary comparison of all eight portfolios and offered an overview of the remaining analysis components to be presented at the final stakeholder meeting. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 4 are included in Appendix A.

2.1.5 Stakeholder Meeting 5

NIPSCO's fifth stakeholder meeting was held on October 28, 2024. In this fifth meeting, NIPSCO reviewed the overall IRP process and summarized responses to feedback and questions provided since the fourth stakeholder meeting. NIPSCO then reviewed the composition of the eight portfolio concepts that were presented in Stakeholder Meeting 4 and, in direct response to feedback from stakeholders, introduced two new portfolios based on a flat load forecast (without data center growth) in response to stakeholder feedback.

NIPSCO then provided the details of its full portfolio analysis for all portfolios across all of its planning scenarios. This included a review of the net present value of revenue requirements for each portfolio and observations on the key relationships between portfolio concepts and across the range of market conditions embedded in the five IRP scenarios. NIPSCO then provided a summary of its stochastic analysis, summarizing key findings for the portfolios associated with forced market exposure risk and cost risk. Next, NIPSCO summarized sensitivity analysis that was performed for a high emerging load sensitivity and an alternate DSM sensitivity. Within the high emerging load sensitivity, NIPSCO summarized expected resource additions over time under very high load growth conditions, while the DSM sensitivity evaluated the implications on portfolio composition and costs of implementing more aggressive DSM programs.

NIPSCO then presented its proposed scorecard, which included metrics associated with affordability, rate stability, environmental sustainability, reliability, and positive social and economic impacts. NIPSCO then reviewed its preferred resource plan and preliminary action plan and responded to stakeholder questions and feedback. The meeting presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 5 are included in Appendix A.

NIPSCO's 2024 IRP is the result of analysis performed by NIPSCO that includes consideration of stakeholder input. NIPSCO has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. NIPSCO appreciates the participation of its stakeholders, including the Commission staff, the OUCC, NIPSCO's largest industrial customers, and community action groups, all of which participated extensively throughout the IRP development process. NIPSCO's stakeholders and Commission staff provided valuable feedback throughout the process, which has been considered and incorporated as applicable. The written feedback NIPSCO received, as well as the Company's responses, is included in Appendix A. Despite best efforts to address and resolve all input from stakeholders, there were instances wherein NIPSCO still incorporated, for example, methodologies that were not supported by all stakeholders.

2.2 Other Stakeholder Input Since NIPSCO's Last IRP

2.2.1 IURC Contemporary Issues

NIPSCO participated in the Commission's IRP Contemporary Issues Technical Conferences that occurred since NIPSCO completed its last IRP and incorporated learnings and key topical areas in its 2024 IRP activities. Meeting dates and topics discussed are summarized in Table 2-1.

Table 2-1: IURC Contemporary Issues Meeting Dates and Topics

Date	Topics
September 22, 2022	• MISO seasonal resource adequacy construct • Resource adequacy in PJM • Interaction between energy efficiency and demand response
October 20, 2023	• ISP • Building on TDSIC to support ISP
June 6, 2024	• Resource adequacy • Capacity accreditation and reforms • Load forecast development and use in PJM and MISO

2.2.2 2021 IRP Feedback and 2024 Process Improvement Efforts

NIPSCO strives to continuously improve all aspects of its resource planning process, and, for the 2024 IRP, NIPSCO reviewed the major feedback it received throughout the 2021 IRP process and implemented key improvements. The process improvements in the 2024 IRP were designed to enhance the robustness of the load forecast, perform a more detailed demand response assessment, improve upon NIPSCO's portfolio modeling approach, and improve stakeholder collaboration with earlier sharing of modeling files and analysis inputs and outputs. Table 2-2 summarizes the major areas of feedback received on NIPSCO's 2021 IRP and the improvements that were included in the 2024 IRP process.

Table 2-2: 2024 IRP Process Improvements

Category	2021 IRP Feedback	2024 Improvement Plan
1 Load Forecast	• More detail on Electric Vehicle (EV) forecast; for example, penetration has not been able to separate non-NIPSCO-serviced light-duty vehicles (LDVs) from total counts in counties served by more than one utility • Clearer analytic methods regarding forecasting demand from large industrial customers	• More rigorous EV modeling with focus on vehicle counts within service territory and by class and separate truck corridor analysis • Additional econometric analysis of industrial loads, as well as review of potential additional emerging industrial load types (i.e., data centers)
2 Demand-Side Resources	• Interaction between energy efficiency (EE) and demand response (DR) resources require further consideration; more attention to meter-based pay-for-performance program designs	• Additional DSM evaluation, including integration with AMI and EV charging management • Continued assessment of distributed energy resources (DERs)
3 Portfolio Analysis	• Positive feedback on reliability assessment: • "Based on this initial effort, [NIPSCO] is well positioned to provide future analytical improvements" • Other stakeholders remain interested in various alternative technologies (RICE, storage, grid-forming inverter-based technology SMR)	• Advance continuous improvement around reliability analysis and quantification of risk • Ensure full evaluation of a wide range of new technologies either via the RFP or other means (CCS at Sugar Creek, hydrogen, SMR, LDES)
4 Stakeholder Collaboration	• Joint Commenters requested increased collaboration in the IRP process and the RFP process • "…comments emphasized the need for continued collaboration and improvement between stakeholders and NIPSCO for the next IRP filing"	• Facilitate the procurement of Aurora Energy Forecast Software licenses to interested stakeholders to enable visibility into certain modeling files • Provide opportunity for feedback on upcoming RFP for interested stakeholders under a Non-Disclosure Agreement

2.2.3 Equitable Transition

As the resource mix and generation technologies in the industry continue to transition, the topic of equity or "just transition" to ensure all customers and communities are included has surfaced as an important issue to address. NIPSCO's vision of an equitable transition is one that improves universal access to energy to customers and communities, ensures inclusion of all stakeholders in strategy/decision-making, and ensures a fair division of costs and benefits.

NIPSCO recognizes the importance of equity and a "just transition" for NIPSCO's customers and communities as the generation portfolio evolves. As part of the 2024 RFP solicitations, NIPSCO incorporated proposal-specific benefit and risk factors outlined in the evaluation criteria, which included, but were not limited to, impacts on local communities that NIPSCO serves, minority- or women-owned business enterprises, and the enterprise's supplier diversity spending. NIPSCO also issued an RFP event for NIPSCO-owned DER opportunities over the next five years to support the energy needs of local communities.

In the 2024 IRP Stakeholder process, the topic of equity considerations was discussed, including a recommendation that NIPSCO consider the addition of an equity metric as part of its scorecard. NIPSCO welcomed this discussion and is always interested in engaging broadly with stakeholders on this important topic. NIPSCO recognizes that measuring equity in the energy transition is a complex process and is taking steps to further expand its knowledge and understanding of different ways and approaches to evaluate this issue. NIPSCO looks forward to engaging in a statewide dialogue with the Commission, other utilities, and interested stakeholders on the topic of equity in future IRP Contemporary Issues Technical Conferences and other forums. Although equity was not adopted as a formal part of NIPSCO's scorecard, NIPSCO will continue to examine future resource decisions within the context of broader issues like equity and, where possible, will seek to develop metrics and measures to better assess the impact of those decisions.

2.3 Overall IRP Approach

NIPSCO's 2021 IRP is in compliance with the Commission's IRP Rule. A matrix showing NIPSCO's compliance with each section of the IRP Rule (providing a reference to the appropriate Section(s) of the IRP) is included in Section 11: Compliance with IRP Rule.

NIPSCO's IRP team included experts from key areas of NIPSCO and its affiliate NiSource Corporate Services Company. In addition, the energy consultants identified in Table 2-3 also provided input.

Table 2-3: 2024 IRP Consultants

Charles River Associates (CRA) 200 Clarendon Street Boston, MA 02116	Provided fundamental long-term scenario forecasts, performed the NIPSCO load forecast, and performed all portfolio modeling and analysis. A separate division of CRA provided assistance in administering the All-Source RFP and evaluating the responses.
ElectroTempo 4201 Wilson Blvd, Suite 700 Arlington, VA 22203	Performed analysis associated with highway corridor heavy-duty vehicle charging.
GDS 1850 Parkway Place, Suite800 Marietta, GA 30067	Developed DSM measures inputs for a long-term DSM forecast.
Demand Side Analytics 691 John Wesley Dobbs Ave NE Suite V3 Atlanta, GA 30312	Provided assistance with analyzing demand response measures and opportunities.

NIPSCO's long-term resource planning process includes five major steps, as summarized in Figure 2-1 and further discussed in separate sub-sections below.

1. The first step in this process is to identify objectives and metrics.

2. Next, NIPSCO develops market perspectives for key variables such as customer demand, environmental policy, and commodity price outlooks. This involves the creation of distinct thematic "states-of-the-world" that represent potential future operating environments for NIPSCO.

3. Then NIPSCO develops integrated resource strategies or portfolios of options.

4. NIPSCO then performs detailed modeling and analysis to evaluate the performance of these various resource portfolios across a range of potential futures as well as a distribution of key stochastic variables.

5. Finally, NIPSCO evaluates tradeoffs and selects a preferred portfolio. NIPSCO's goal is to develop a resource plan that is reliable, compliant with all regulations, diverse, flexible, and affordable for customers with careful consideration of all stakeholder viewpoints.

Figure 2-1: NIPSCO's IRP Process Steps



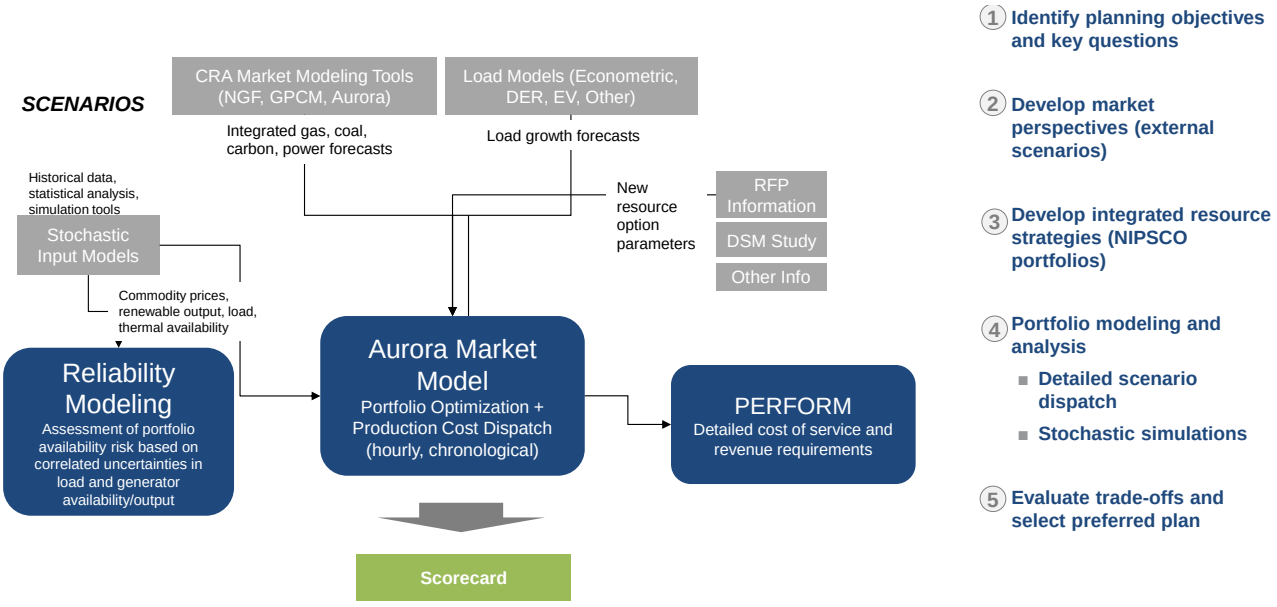
The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs. The short-term action plan identifies the steps NIPSCO will take over the next three to five years to implement the long-term strategic plan.

NIPSCO recognizes future economic, policy, market design, and technology changes are difficult to accurately predict. While the 2024 IRP addresses a wide range of plausible market conditions and portfolio strategies, new information is evaluated and incorporated as it becomes available as part of NIPSCO's commitment to continuous planning.

Consistent with the principles set out above, the 2024 IRP identifies a preferred portfolio plan for NIPSCO over a 20- to 30-year[2] planning horizon that seeks to deliver reliable, compliant, flexible, diverse, and affordable electric service to its customers. NIPSCO's 2024 IRP was performed according to the detailed planning approach process that is outlined in Figure 2-2 and described in more detail below.

[2] Note that fundamental market modeling and portfolio dispatch is performed over a 20-year period, and NIPSCO performs a 10-year end effects analysis in the financial modeling framework to arrive at 30-year NPVRR estimates. The end effects analysis grows variable costs at the rate of inflation, but specifically accounts for full rate base accounting and incorporates the impacts of contract expirations during the end effects period.

Figure 2-2: Overall Integrated Resource Planning Approach



2.3.1 Step 1: Identify Planning Objectives and Key Questions

The first step in NIPSCO's planning approach was to identify planning objectives and key questions to guide the overall analysis framework. These key questions and objectives influence all other elements of the IRP process, including the structuring of market perspectives, the identification of potential resource strategies, and the definition of objectives and metrics against which to evaluate future portfolios in NIPSCO's integrated scorecard framework. The major themes of the 2024 IRP are described in more detail below.

2.3.1.1 Meeting New Load Growth

As introduced during the second stakeholder advisory meeting, NIPSCO has seen a significant increase in the potential for new large loads, primarily hyperscaler data centers, to enter its service territory. NIPSCO believes that Northern Indiana is a favorable location for data centers to locate because of the low risk for natural disasters; a robust transmission network; available land, strong connectivity and fiber; access to water; proximity to customers, a major metropolitan area, and construction labor; and favorable state policy. As a result of these emerging trends, NIPSCO developed a Reference Case load forecast that assumes two to three potential data center projects come to fruition, driving up to 2,600 MW of new load for the system. In addition, an emerging high load sensitivity was developed to incorporate up to six potential data center projects entering the system at a level of up to 8,600 MW.[3]

[3] Such load additions are not attributable to a specific customer(s) but represent NIPSCO's attempt to reasonable estimate total load additions that may come to fruition under various future states of the world.

NIPSCO's 2024 IRP seeks to evaluate the implications associated with a range of new data center load growth trajectories to assess the type and timing of new resource additions to its existing portfolio. NIPSCO acknowledges that final data center growth trajectories remain uncertain, and thus, NIPSCO will need to be flexible in its resource procurement activities based on the range of outcomes studied in the 2024 IRP.

2.3.1.2 Ensuring Reliability in the Context of Changing Market Rules

Over the last several years, MISO has been actively evaluating emerging reliability issues within its footprint, particularly through its Reliability Imperative framework, which was initiated in 2020,[4] and which has identified the following key initiatives: ensure resources are accurately accredited; identify critical system reliability attributes; and ensure accurate pricing of energy & reserves. One pillar in the Reliability Imperative is "Market Redefinition," and as part of its effort to redesign key elements of the market, MISO has implemented or proposed to implement several key reforms in recent years:

- In 2023, MISO implemented a four-season capacity construct with obligations and resource accreditations varying by the four seasons across the MISO Planning Year.[5]
- By 2025, MISO plans to implement a "downward sloping" reliability-based demand curve to value capacity across a range of reserve margin levels.
- On March 28, 2024, MISO filed its D-LOL market design proposal with the FERC,[6] driving toward marginal capacity accreditation, with obligations and resource accreditations focused on performance during tight margin hours. On October 25, 2024, FERC approved this filing, and NIPSCO expects it to enter into force for the 2028/29 planning year.

The D-LOL methodology, in particular, will have significant impacts for how NIPSCO's resources are accredited. Accreditation for wind, solar, and storage resources will be evaluated based on a combination of forward-looking loss of load analysis performed by MISO and actual three-year historical availability during MISO's risky hours (Tier 1 and Tier 2 resource adequacy hours).

Although future accreditations are highly uncertain, NIPSCO's 2024 IRP has evaluated portfolios under the D-LOL framework in order to assess the potential implications of different accreditation outlooks, including under the current market rules and the best information available to NIPSCO on potential changes under D-LOL. These are summarized in Figure 2-3, Figure 2-4,

[4] See: https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[5] Note that the four-season capacity construct was anticipated in NIPSCO's 2021 IRP, with the preferred portfolio developed under the expected construct.

[6] See: https://cdn.misoenergy.org/2024-03-28%20Docket%20No.%20ER24-1638-000632361.pdf

Figure 2-5, and Figure 2-6 for solar, wind, gas peaking, and four-hour storage capacity, respectively.[7] Given ongoing market design uncertainty and evolving accreditation forecasts associated with D-LOL implementation, NIPSCO will need to ensure near-term capacity addition decisions are flexible enough to adapt to changing market rules.

Figure 2-3: Accreditation Expectations under Different Constructs – Solar

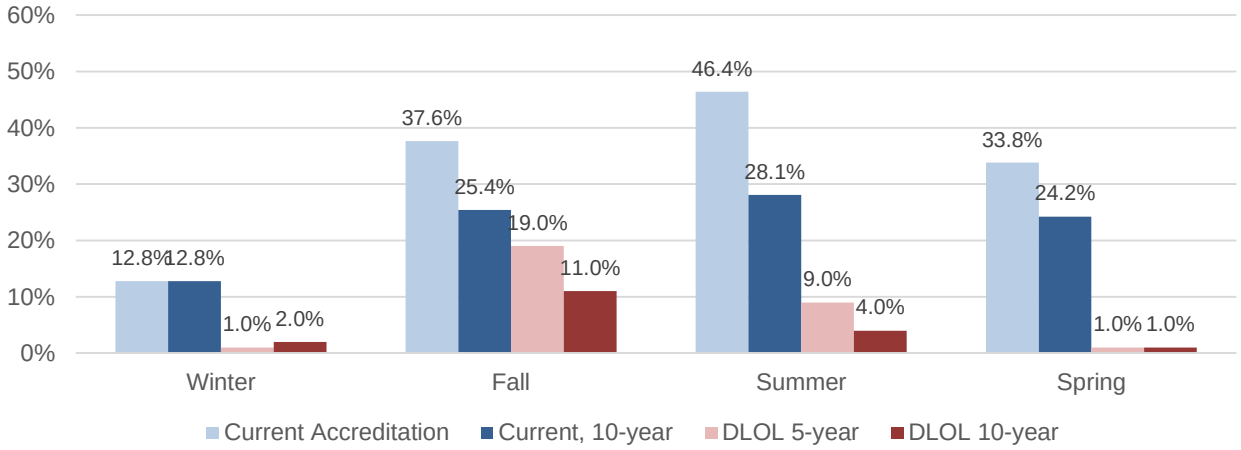
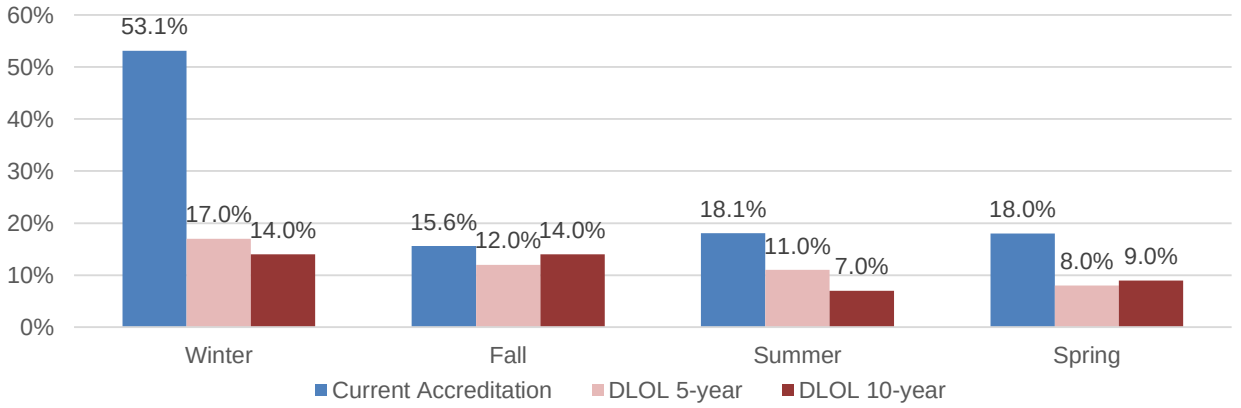


Figure 2-4: Accreditation Expectations under Different Constructs – Wind



[7] D-LOL accreditation expectations adopted from MISO RASC meeting in January 2024: https://cdn.misoenergy.org/20240117%20RASC%20Item%2007a%20Accreditation%20Presentation%20(RASC-2020-4%20and%202019-2631379.pdf

Figure 2-5: Accreditation Expectations under Different Constructs – Gas Peaking

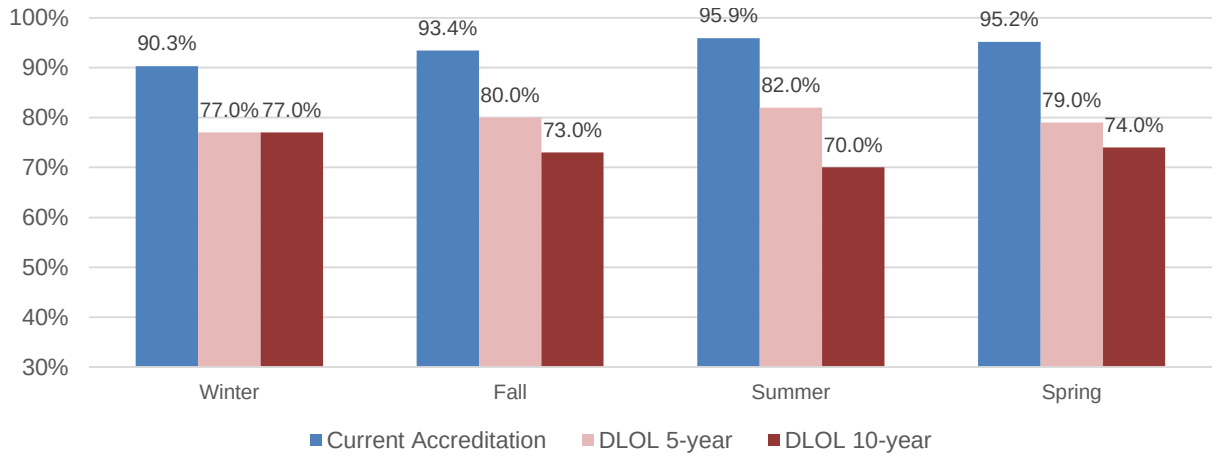
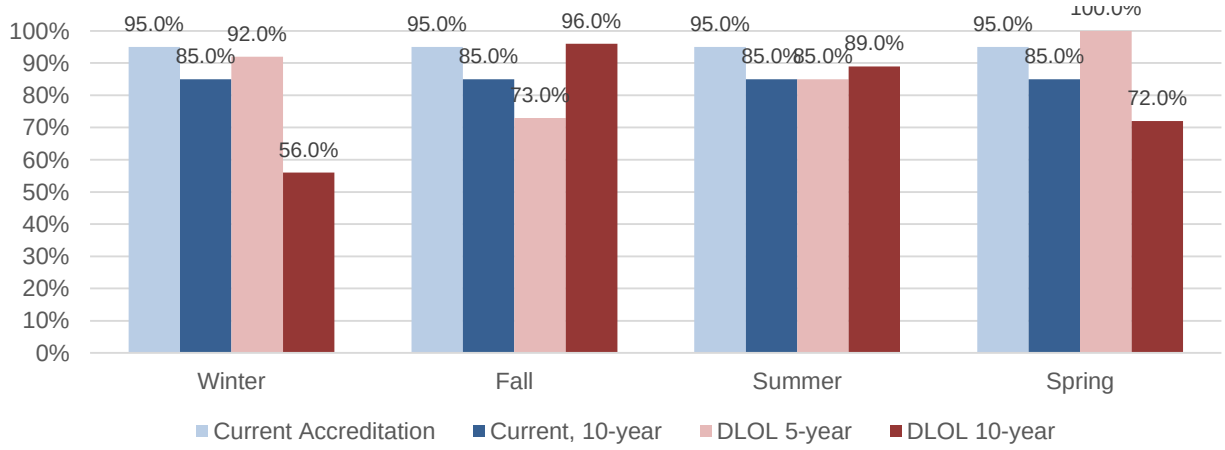


Figure 2-6: Accreditation Expectations under Different Constructs – 4-Hour Storage



2.3.1.3 Navigating Dynamic Environmental Policy Drivers and NIPSCO's Sustainability Objectives

On April 25, 2024, the EPA finalized greenhouse gas emissions rules for the power sector. These rules limit the future operation of coal-fired power plants and govern the emissions and operational profiles of new natural gas-fired units. Most importantly, capacity factor limitations are included for new combined cycle plants. In addition, federal tax credit policy associated with clean energy resources, energy storage, CCUS, and hydrogen may change in the future.

Meanwhile, NIPSCO remains committed to supporting NiSource's Net Zero Goal and will assess the best pathways for achieving it based on developments in federal policy, market rules, and technology advancement. Given legal challenges to the EPA GHG Rules and potential changes to EPA regulations and federal legislation under a new President and Congress, NIPSCO must be

flexible in adapting its portfolio to future policy change. To reflect uncertainty, as part of the 2024 IRP, NIPSCO:

- Evaluated portfolio constructs with and without the GHG Rules in place; and
- Evaluated scenarios with different long-term assumptions associated with the availability of federal production tax credits and investment tax credits.

2.3.1.4 Preserving the Flexibility and Adaptability of the Portfolio

A key element of NIPSCO's 2018 and 2021 IRPs was *flexibility*. The preferred plans from both of these prior IRPs specifically incorporated expectations that NIPSCO would regularly evaluate new resource options, track technology change, and adapt to market rules and policy evolution. And NIPSCO's implementation of its energy transition has done exactly that by; (i) conducting additional sets of RFPs to secure projects as needed; (ii) adjusting NIPSCO's procurement strategy to integrate storage and shift the amount of solar and wind in the portfolio; (iii) adjusting resource retirement dates and online dates in response to external market factors like supply chain constraints and tariff pressures; and (iv) evolving the analytical tools used in IRP studies to incorporate broader risks and considerations.

In the 2024 IRP, NIPSCO identified key market, policy, and regulatory developments early in the planning process to ensure market scenarios and portfolios were constructed to be flexible to a dynamic market. These included:

- Significant demand growth across the power sector as a result of data center loads;
- The documentation of the Five Pillars of long-term planning identified by the Indiana 21st Century Energy Task Force;
- MISO's D-LOL filing associated with capacity accreditation;
- EPA's GHG rules;
- NIPSCO conducted RFP events to solicit actionable resource offers of all types and duration;
- NIPSCO deployed a portfolio construction process that did not rely solely on least cost optimization, but also assessed a wide range of strategies to understand the implications of different capacity accreditation and emissions constraints.

2.3.1.5 Scorecard Definition

With these key planning questions and themes identified, NIPSCO worked to define a series of scorecard objectives and indicators against which to measure portfolio options. The scorecard is a means of reporting key metrics for different portfolio options to transparently review tradeoffs and relative performance. It does not produce a single score or ranking of portfolios, but serves as a tool to facilitate decision-making.

For its 2024 IRP scorecard, NIPSCO identified five major planning objectives and multiple metrics within seven key indicator categories, as summarized in Figure 2-7. The objectives include Affordability; Rate Stability; Environmental Sustainability; Reliable, Flexible, and Resilient Supply; and Positive Social and Economic Impacts. These are similar to those used in the 2021 IRP and track closely and are consistent with the Five Pillars of long-term planning identified by the Indiana 21st Century Energy Task Force.[8]

Figure 2-7: Key Scorecard Objectives and Indicators

Objectives	Indicators
Affordability	Cost to Customer
Rate Stability	Cost Certainty
	Cost Risk
	Lower Cost Opportunity
Environmental Sustainability	Carbon Emissions
Reliable, Flexible, and Resilient Supply	Reliability, Flexibility
Positive Social, & Economic Impacts	Local Investment in Economy

2.3.2 Step 2: Develop Market Perspectives

Prior to performing any portfolio-specific analysis, NIPSCO developed perspectives on key *external* market drivers and other major planning assumptions. This involved the use of several market models and forecasting approaches to arrive at a Reference Case set of inputs and four alternative scenarios against which to evaluate resource options. The elements involved in this step are described in more detail below.

2.3.2.1 Key Market Forecast Inputs

Market and commodity price forecasts are important drivers for NIPSCO's IRP, since they influence the variable costs of operation for many resources, the dispatch of certain power plants, and NIPSCO's interaction with the MISO market. CRA produced commodity price forecasts for major inputs, including natural gas prices, coal prices, environmental policy and emission allowance prices, and power prices (energy and capacity) for the Reference Case and four alternative integrated market scenarios. For certain inputs, CRA relied on support from NIPSCO's subject matter experts for details or assumptions that are specific to NIPSCO's current operating

[8] The Five Pillars include Reliability, Resilience, Affordability, Stability, and Environmental Sustainability IRP.

fleet. For example, for coal pricing, delivered coal contract details and expected coal transportation rates were provided by NIPSCO's Fuel Supply group to conform to near-term price expectations for the existing fleet of plants. Long-term fundamental forecasts were blended in over time. Figure 2-8: presents a summary of the source and reference information for each of the major market inputs.

Figure 2-8: Major Market Input Sources

Major Input	Source	Section Reference for More Detail
Natural Gas Prices	CRA forecasts and NIPSCO operations team	8 (fundamental forecasts, including scenarios and stochastic inputs) 4 (current gas procurement strategies)
Coal Prices	CRA forecasts and NIPSCO fuel supply group	8 (fundamental forecast) 4 (coal procurement and current contracts/ transportation arrangements)
Emission Prices and Environmental Regulation	CRA forecasts and NIPSCO environmental group	7 and 8
MISO Power Prices	CRA forecasts	8
MISO Capacity Prices	CRA forecasts	8

CRA relied on the following models to perform this work:

- CRA's NGF model, which provides a bottom-up forecast of North American gas production and prices with a focus on shale gas supply and other unconventional resources. Key NGF outputs include a long-term price forecast for domestic natural gas, as well as breakeven costs and production data for major gas basins across the United States. NGF is a national model, useful for macroeconomic scenarios. CRA also licenses the GPCM for regional basis analysis.

- The Aurora model, which CRA licenses, performs regional long-term capacity expansion analysis, and produces hourly MISO market prices at a zonal level based on a fundamental dispatch of the market. Market inputs for the Aurora model include fuel prices, emission prices, regional load forecasts, existing resource parameters and announced regional capacity additions and retirements, and costs and operational parameters for new technology resource options. CRA also deploys a capacity market model, which produces an internally consistent capacity price outlook based on MISO market rules.

- Natural gas and power price stochastic inputs were developed with CRA's MOSEP model. The tool's Monte Carlo engine simulates price deviations around expected paths based on historical volatility and natural gas-power correlation to yield

hundreds of iterations of daily and hourly price paths. CRA also generated correlated synthetic wind output, solar output, and NIPSCO load iterations using *CRA AdequacyX* – Charles River Associates' proprietary probabilistic reliability analysis tool. The details of the stochastic development process are discussed in more detail in Section 8.

2.3.2.2 Environmental Planning Inputs

For the 2024 IRP, the joint NIPSCO-CRA team developed a range of potential environmental policy input assumptions across market scenarios, given uncertainty regarding federal legislative policy and regulation at the U.S. EPA. These environmental planning inputs included scenarios with and without the recently issued EPA GHG Rules for the power sector, with and without the long-term continuation of federal tax credits for clean energy that were extended and or/expanded through the Inflation Reduction Act of 2022, and with and without CO2 pricing. NIPSCO's environmental group provided perspective on the policy ranges and the likely impacts for NIPSCO's fleet. A comprehensive review of key environmental planning drivers is provided in Section 7.

2.3.2.3 Energy and Demand Forecast

For the 2024 IRP, CRA developed an independent load forecast for NIPSCO's energy sales and expected future summer and winter peaks. The 2024 IRP included a robust accounting of the impacts of historical DSM, as well as quantitative scenario-based projections of electric vehicle and customer-owned distributed energy resource penetration and their impacts on NIPSCO's load growth outlook. Scenario variables also included economic growth, industrial load uncertainty, broader market-wide electrification, and large economic development (data center) load growth. All methods, assumptions, and detailed forecast results are provided in Section 3.

2.3.2.4 Existing NIPSCO Portfolio Parameters

NIPSCO's IRP models incorporate all elements of the existing portfolio. NIPSCO's generation operations and planning groups provided the following characteristics for the existing set of resources: capacity, heat rates, emission rates, other operational characteristics of fossil-fired resources, variable O&M costs, fixed O&M costs, forced outage rates, maintenance schedules, must run schedules for coal units, energy and capacity contracts, feed-in-tariff contracts, existing DSM data, and renewable shapes. Certain details regarding the existing fleet are provided in Section 4.

2.3.2.5 New Resource Parameters

NIPSCO relied on multiple sources for major input assumptions associated with new resource options. DSM resource options and costs were developed by GDS and Demand Side Analytics, as described in Section 5. Supply-side resource options were developed largely from the 2024 RFPs. The 2024 RFPs provided real-world cost information and resource operational characteristics, including capacities, heat rates, and expected capacity factors for renewable resources. NIPSCO supplemented the RFP data with third-party research and internal cost

estimates from its Major Projects group for additional generic technology types. Section 4 describes the overall new supply-side resource process in more detail, along with a review of emerging technologies that may be viable over the long-term for NIPSCO and across the broader MISO market.

2.3.2.6 Planning Reserve Margin Target

NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy. MISO's most recent seasonal reserve margin targets were used under current market rules: 9% in Summer, 27% in Winter, 14% in Fall, 27% in Spring. For the reserve margin used under the D-LOL analysis, NIPSCO used a coincidence factor based on information provided to NIPSCO by MISO in Spring 2024 that developed an expected planning reserve margin requirement obligation under D-LOL rules for the 2028/29 planning year based on backcasting analysis of the 2023/24 planning year. This coincidence factor aims to approximate NIPSCO obligation for the season based on its expected load during all MISO risk hours and not just during the single peak hour. On a peak load basis, the implied seasonal reserve margins were: 4.2% in Summer, 2.8% in Winter, 9.2% in Fall, 1.2% in Spring. The implied reserve margins under D-LOL are lower because the system risk hours are not necessarily coincident with times of NIPSCO's internal peak.

2.3.2.7 Financial Assumptions

Several financial assumptions are relevant to projecting annual revenue requirements, such as the expected return on equity and debt, tax rates, and the discount rate used when calculating the NPV. A summary of the major financial assumptions used in the 2021 IRP is provided in Figure 2-9.

Figure 2-9: Major Financial Assumptions

Financial Assumption	Value
Cost of Equity	9.80%
Cost of Debt	4.76%
Equity %	58.60%
Debt %	41.40%
After-Tax Weighted Average Cost of Capital	7.22%
Federal Income Tax Rate	21.00%
State Income Tax Rate	4.90%
Blended Income Tax Rate	24.87%
Property Tax Rate	2.16%
Discount Rate	7.22%
Allowance for Funds Used During Construction%	7.44%
Blended Depreciation Rate for Existing Assets	3.88%

2.3.3 Step 3: Develop Integrated Resource Strategies

The third major step in the 2024 IRP process was to develop resource strategies or portfolios for further evaluation. Foundational to this step was establishing NIPSCO's starting supply-demand position. On the supply-side, NIPSCO is currently in the midst of retiring its coal-fired Schahfer and Michigan City units and replacing them primarily with wind, solar, storage, and natural gas peaking resources. Meanwhile, capacity accreditation for all resource types is uncertain as MISO rules evolve. On the demand side, NIPSCO currently expects significant load growth associated with new large data center loads entering its system.

As shown in Figure 2-10 and Figure 2-11 for the summer and winter seasons, respectively, NIPSCO faces an uncertain future capacity gap as a result of potential load growth and potential capacity accreditation changes. The gap is expected to materialize in 2028 after the retirement of NIPSCO's final coal-fired unit at Michigan City and grow over time. As shown, both the capacity accreditation and NIPSCO obligation are expected to change in 2028 after the implementation of the D-LOL rules.

Figure 2-10: Starting Supply-Demand Balance – Summer with and without D-LOL

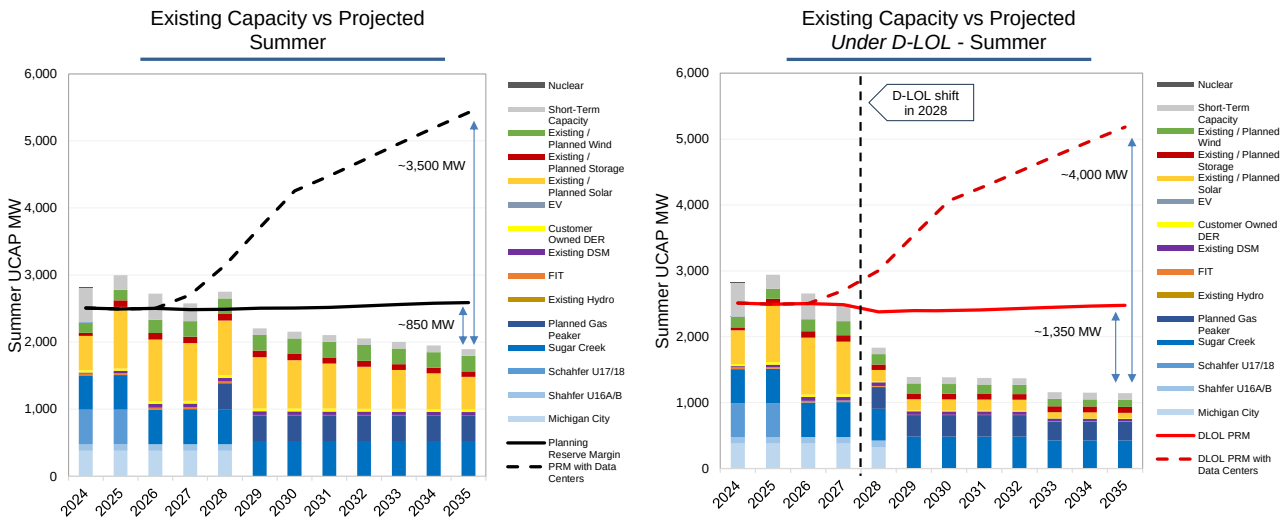
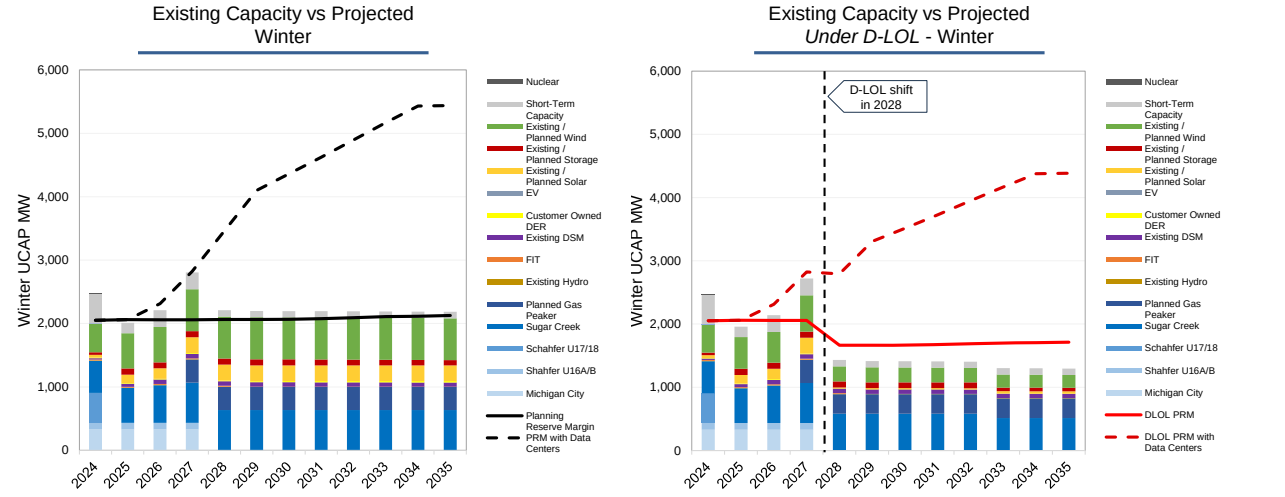


Figure 2-11: Starting Supply-Demand Balance – Winter with and without D-LOL



With this foundational starting point, the 2024 IRP's portfolio development process relied on multiple inputs and approaches, which are described in more detail in Section 4 (Supply Side Resource Options), Section 5 (Demand-Side Resource Options), and Section 9 (Portfolio Analysis). In the context of the major themes identified in step one and the starting supply-demand balance noted above, NIPSCO developed six different portfolio concepts around accreditation and emission intensity through least cost portfolio optimization analysis. Variants were also developed based on load growth sensitivities and future decarbonization pathways. The analysis is described in more detail in Section 9.

2.3.4 Step 4: Portfolio Modeling

After detailed portfolios were constructed, each of them was evaluated in CRA's suite of resource planning tools, namely Aurora and a utility financial model known as PERFORM. The Aurora model performs an hourly chronological dispatch of NIPSCO's portfolio within the MISO power market, accounting for all variable costs of operation, all contracts or power purchase agreements, and all economic purchases and sales with the surrounding market. Aurora produces projections of asset-level dispatch and the total variable costs associated with serving load. It also produces estimates for other key metrics, such as carbon dioxide emissions over time and capacity and generation by fuel type.

The Aurora output is then used by CRA's PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, and financial accounting of depreciation, taxes (including detailed accounting associated with federal tax credits) and utility return on investment. The PERFORM model produces annual and net present value estimates of revenue requirements. The full set of portfolio modeling is undertaken for all portfolio options for the Reference Case and each individual integrated market scenario.

2.3.5 Step 5: Evaluate Tradeoffs and Produce Recommendations

The final step in NIPSCO's IRP process is to evaluate the various portfolios with an integrated scorecard and produce recommendations for a preferred plan. As discussed in Step 1, NIPSCO identified several planning objectives for its scorecard. In this step, metrics were recorded against all key planning criteria, and tradeoffs were evaluated. Ultimately, NIPSCO management is responsible for selecting the preferred portfolio based on an assessment of all options and scorecard metrics. This process and the preferred portfolio selection is described in Section 9.

Section 3. Energy and Demand Forecast

3.1 Introduction and Major Highlights of the Forecast

This section provides an overview of NIPSCO's load forecast. For the 2024 IRP, NIPSCO worked with CRA to produce a comprehensive load forecast by customer class and load category. This entailed an econometric core load forecast for residential, commercial, small industrial, and large industrial customers,[9] plus projections for EV demand and BTM DER f

penetration throughout the service territory. NIPSCO also developed a view on the potential for large economic development projects, particularly data centers, to drive additional demand growth. Major highlights of the forecast include:

- As part of its 2024 load forecasting efforts, NIPSCO has identified several large economic development projects that could contribute significant load growth to the system. To capture this new source of demand, NIPSCO developed two large load sensitivities to supplement the base econometric forecast. Data center growth has the potential to add 21,810 to 72,140 GWh to the annual sales forecast by 2035 and between 2,600 and 8,600 MW to peak load.

- In the Reference Case, NIPSCO's energy sales are projected to grow at a CAGR of approximately 11.3% over the next 20 years, *including the impact of new large economic development loads*. The summer and winter peaks are projected to increase by 8.9% and 10.6%, respectively. Prior to the inclusion of such loads, NIPSCO's energy sales were projected to growth at a CAGR of approximately 1.1% over the next 20 years.

- Residential and commercial customer counts are projected to grow at CAGRs of 0.87% and 1.02%, respectively, with the industrial customer count projected to decline at a rate of 0.26% per year. Overall sales to residential customers are projected to increase by 0.37%, despite sales per customer declining. The overall sales to commercial customers are similarly projected to increase by 0.36%, driven by growing customer count but modestly declining sales per customer. The sales to small industrial customers are projected to decline by 0.15%, driven by modestly declining customer count and flat sales per customer.[10]

- EV growth has the potential to add between approximately 700 to 1,800 GWh to the annual sales forecast by 2043 and between 140 and 360 MW of summer peak impact.

[9] Additionally, railroad, street lighting, public authority, and company use energy forecasts are incorporated in the total energy forecast. However, the load forecast for these customer classes has been projected using a simple moving average assumption based on historical data, rather than a regression estimation method.

[10] The projections in this paragraph exclude the new large economic development loads referenced in the immediately preceding paragraphs.

EVs also have the potential to substantially shift the time of peak load, depending on consumer behavior and potential future time of use rate design incentives.

- Customer-owned DERs in the form of residential and commercial solar resources have the potential to reduce the sales forecast by approximately 150 to 400 GWh. However, this resource is unlikely to materially reduce peak demands, given expectations for overall hourly load profiles to shift to times before or after the sun has risen or set.

- NIPSCO's scenario and sensitivity analysis provides a broad range of potential load growth outcomes based on uncertainty regarding future economic growth, EV and DER penetration, other electrification, potential industrial load migration, and large economic development growth.

3.2 Forecasting Methodology Overview

For the 2024 IRP, NIPSCO has made several enhancements to its load forecasting methodology, which are discussed in detail in this section. The overall load forecasting methodology includes six key steps, which are illustrated in Figure 3-1 and described as follows:

- **Data Gathering**: Compilation of historical data, including historical energy consumption and number of customers by class, historical demand side management program impacts, Moody's macroeconomic variables (such as state-level data on number of households, employment, and personal income), weather variables (heating and cooling degree days based on historical temperature and humidity), and historical data associated with EV and DER penetration.

- **Weather Normalization:** Development of weather-normalized energy sales by class (kWh/customer) for the historical period, *excluding* historical DSM program impacts.

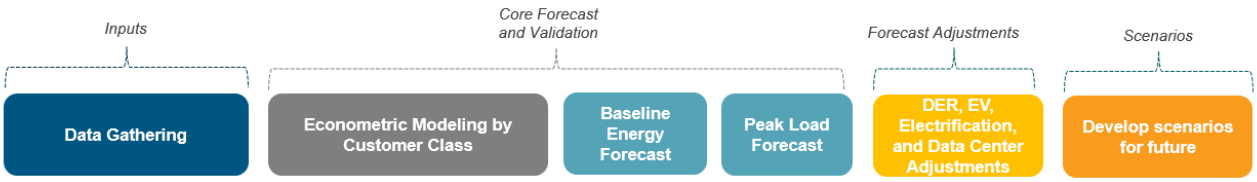
- **Econometric Modeling by Customer Class:** Testing of all economic and demographic "driver" variables in a dynamic regression system and performance of post-estimation tests on econometric models' specification and forecasting performance (for example, Systemic Mean Absolute Percentage Errors).

- **Baseline Energy and Peak Load Forecast Development:** Development of baseline customer count and energy forecasts for each NIPSCO customer rate class, *excluding* historical DSM, and development of accompanying peak load forecasts using the energy forecast and load factors by customer rate class.

- **Forecast Adjustments**, including:
    - Adjustments to the load forecast to incorporate existing and planned *known* DSM programs.
    - Synthesis of forecasts for elements of the future load associated with emerging market trends, including EVs, DERs, other sources of electrification, and new large economic development loads like data centers, inclusive of transmission and distribution losses and accounting for changing load shapes.

- **Scenario Development:** Evaluation of alternative economic growth in econometric models and development of ranges for EVs, DERs, other electrification, industrial load, and new large economic development loads like data centers based on fundamental analysis and other inputs.

Figure 3-1: Summary of NIPSCO Load Forecasting Methodology



3.3 Base Customer Count, Electric Energy, and Peak Demand Forecast

3.3.1 Data Gathering, Weather Normalization, and Econometric Modeling

NIPSCO developed *baseline* forecasts for customer count and energy usage per customer separately, employing an econometric analysis of monthly historical customer class data. First, NIPSCO collected historical data by customer class on the number of customers and energy consumption at a monthly level from 2013 through 2023,[11] macroeconomic and demographic indicators for the region from Moody's Analytics,[12] weather data (heating and cooling degree days based on historical temperature) from the National Oceanic and Atmospheric Administration, and information regarding NIPSCO's historical DSM and EE program savings. After estimating regression equations for each customer class, a number of statistical tests were performed to validate the regression equations specifications and forecast errors. NIPSCO selected the presented model based on R-squared, adjusted R-squared, Root Mean Squared Error and Mean Absolute Percentage Error for out-of-sample data. Stata and Python software packages were used to perform the load forecasting analysis.

After constructing datasets for each customer class, NIPSCO developed econometric regression models for forecasting the number of customers for each customer class, controlling for key drivers. These key variables were regional economic and demographic factors, including household counts (for residential and commercial) and employment in the manufacturing sector (for industrial) and dummy variables that control for seasonal and annual impacts. Specifically, household income was the key variable used to forecast residential, commercial customer count,

[11] It is important to note that NIPSCO's baseline load forecast takes out all historical DSM and energy efficiency (EE) savings from historical electric energy consumption prior to the econometric analysis.

[12] Note that the final IRP load forecast was based on economic data from Moody's as of Q4 2023.

and total industrial customers,[13] while the commercial customer count was also based on a measure of employment.[14]

Note that after predicting the total number of industrial customers, these were divided into categories for small industrial customers, large industrial non-531 customers, large industrial 531 Tier 1 customers, and large industrial 531 Tier 2/3 customers. The number of large industrial customers in each class was assumed to remain constant at the current number, while smaller industrial customers were evaluated through NIPSCO's econometric analysis.[15]

A representation of the estimated regression model for the customer count forecast is presented in Equation 3-1.

Equation 3-1: Regression Equation for Number of Customers

$$C_{it} = b_o + b_1 X_{it} + b_{jt}\theta_t + \pi_{it}$$

Where

i=customer class (residential, commercial, total industrial)

t= month

b_o= constant term

C_{it} = number of customers in a given customer class i in month t

X_{it}= Macroeconomic variable (e.g., number of households for residential and commercial classes in a given month i)

$b_1, b_2, .. b_j$ = Estimated coefficients (slopes) for each variable included in the regression model.

π_{it} = random error term

Similarly, NIPSCO developed econometric regression models for predicting energy sales per customer[16] for each customer class that would control for key drivers for energy consumption, including weather and regional economic and demographic drivers. Specifically, key variables for the residential and commercial regression equations included the average class-specific monthly retail rate, heating and cooling degree days, household income (for residential), employment in the manufacturing sector (for commercial), and monthly dummy variables that control for seasonal impacts on energy consumption. A dummy variable was also used to account for changing

[13] The coefficient on the household income variable is positive for residential, commercial, and small industrial customer counts, suggesting that an increase in the household income is associated with an increase in the number of these customers in the NIPSCO service territory.

[14] The coefficient on the employment variable is positive, which indicates that the number of commercial customers in the NIPSCO service territory will increase with increasing levels of employment.

[15] The present number of large industrial customers is 9 large Industrial non-531 customers, 7 large Industrial 531 Tier 1 customers, and 7 large 531 Tier 2/3 customers. These are assumed to continue at constant levels in the Reference Case forecast.

[16] The electric energy forecast is predicted for energy consumption per customer, which is the ratio of total energy consumption by total number of customers in a specific customer class in a given month (i.e., residential energy use per customer (MWh/customer) is calculated as total residential energy consumption (MWh) in a given month divided by the total number of residential customers in that month).

customer behavior following the COVID-19 pandemic. The following variables were used in the development of the electric energy sales per customer model:

- Heating (residential only) and cooling degree day variables control for the impact of weather on electricity consumption. Particularly, the residential and commercial sectors are responsive to outside temperature because a significant portion of electricity consumption is used for air conditioning, and to a lesser extent space heating, for the residential and commercial customer classes.[17]

- Demographic variables (i.e., household income, employment in manufacturing, and overall employment) control for the impact of regional economic factors on electricity consumption.

- Dummy variables control for factors that cannot be controlled with any other variable in regression equations, such as monthly seasonality that is not associated with weather.

- Dummy variables were used to control for sharp changes in customer behavior following the COVID-19 pandemic.[18]

A representation of the estimated regression model for the usage per customer forecast is presented in Equation 3-2.

[17] The expected coefficients on heating degree days and cooling degree days suggest that (i) an increase in the number of heating degree days is associated with higher electricity consumption, specifically due to space heating; and (ii) an increase in the number of cooling degree days is associated with higher electricity consumption, specifically due to space cooling.

[18] This COVID-19 dummy variable was positive for residential use per customer and negative for commercial use per customer. This indicates changing customer behavior, which increases typical residential use and reduces commercial use.

Equation 3-2: Regression Equation for Usage per Customer Forecast

$$D_{it} = a_o + a_2 X_{it} + a_3 \text{Weather}_{it} + a_{jt}\theta_t + a_4 I_t + \varepsilon_{it}$$

Where

i=customer class (residential and commercial)

t= month

a_o= constant term

D_{it}= electric energy usage per customer in a given customer class i in a given month

X_{it}= Macroeconomic variable (e.g., real personal income for residential class in a given month)

$Weather_t$= variables included to control for weather such as heating and cooling degree days

$a_{jt}\theta_t$= time dummies that control for seasonality in demand

I_t= Indicator function for post-2020 years to account for impacts of changing behavior during and following the COVID-19 pandemic

ε_{it}= random error term

$a_1, a_2, a_3, \ldots a_j$ = Estimated coefficients (slopes) for each variable included in the regression model.

Regression models on Moody's variables were not found to provide good predictive power for the sales per customer in the industrial classes, and the industrial classes (small industrial, large industrial non-531, large industrial 531 Tier 1, large industrial 531 Tier 2, and large industrial 531 Tier 3) were found to be highly correlated with relatively stable portions of overall sales (25.45%, 5.38%, 16.06%, 17.46%, and 34.2%, respectively). This indicates that the industrial load is a single overall ecosystem that is driven by underlying long-term, techno-economic trends. The sales for the overall industrial class have historically seen modest declines, but they have stabilized following the COVID-19 pandemic. The industrial sales also showed significant monthly variations, indicating predictable yearly cycles in the industries represented in NIPSCO's footprint. Given these trends, the overall industrial sales were predicted as the post-2020 monthly average. Then, the overall sales were decomposed to the respective classes, based on the historical trends.

Figure 3-2 summarizes the key variables included in both the energy per customer and customer count load forecast equations for residential, commercial, and small industrial customer classes.

Figure 3-2: Econometric Model Parameters for Core Load Forecast

	Residential	Commercial	Industrial
Customer Count Forecast	Household Income	Household Income, Employment	Manufacturing employment, Metals employment
Baseline Sales per Customer Forecast	Household income, HDD, CDD, seasonal monthly dummies, 2020 and after indicator function	Employment, Manufacturing, CDD, seasonal monthly dummies, 2020 and after indicator function	Seasonal average → decomposed by rate class

3.3.2 Industrial Service Structure

The 2024 IRP incorporated NIPSCO's industrial service tariff, known as Rate 531. This industrial service tariff, originally named Rate 831, was included in the settlement agreement in Cause No. 45159 approved by the Commission in 2019, and it gave certain large industrial customers the option to secure their energy and capacity needs, although NIPSCO at all times is the Market Participant in the MISO market. Since then, these rates classes have been renamed as Rate 531. For IRP planning purposes, NIPSCO's load forecast for the large industrial customer class includes Rate 532, Rate 533, and Rate 531 (Tier 1 energy only) customers.[19]

3.3.3 Customer Count Forecast

Historical customer count data indicates that approximately 87% of NIPSCO customers are residential class with a historical CAGR of 0.54% between 2013 and 2024. The commercial class makes up about 12% of NIPSCO customers, and the industrial class makes up about 0.45% of NIPSCO customers. The CAGR between 2013 and 2024 for commercial and industrial classes is 0.76% and *minus* 0.98%, respectively.

Figure 3-3 presents NIPSCO's projected customer count for the Residential class, Figure 3-4 presents NIPSCO's projected customer count for the Commercial class, and Figure 3-6 presents NIPSCO's projected customer count for Industrial customer classes.

The CAGR is also calculated for the number of customers for each customer class projection between 2024 and 2043 in order to provide an understanding on the future growth trends for NIPSCO's customer counts. NIPSCO's forecast projects residential and commercial CAGRs of 0.87% and 1.02%, respectively. The number of industrial customers is projected to decline modestly at a rate of minus 0.26%.

[19] Note that hourly historical meter data for each individual industrial customer is analyzed when developing the load forecast for the large industrial customer class that NIPSCO services. The energy consumption of industrial customers under Tier 2 and Tier 3 on Rate 531 is excluded from the load forecast because this load is not served by NIPSCO.

Figure 3-3: NIPSCO Residential Customer Count Forecast

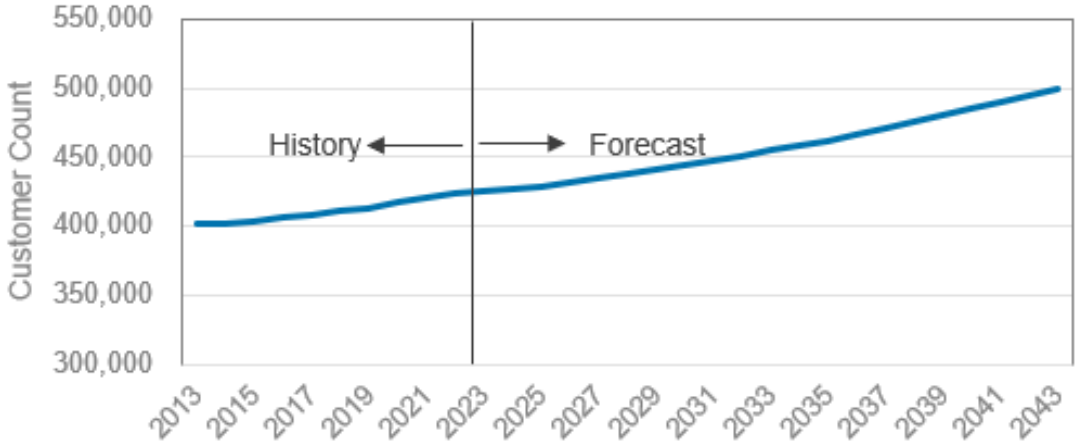


Figure 3-4: NIPSCO Commercial Customer Count Forecast

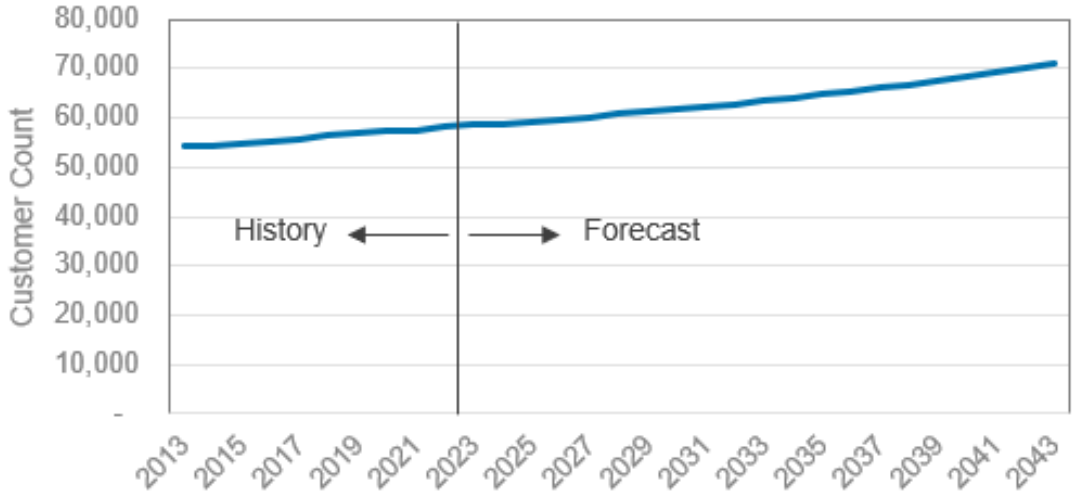
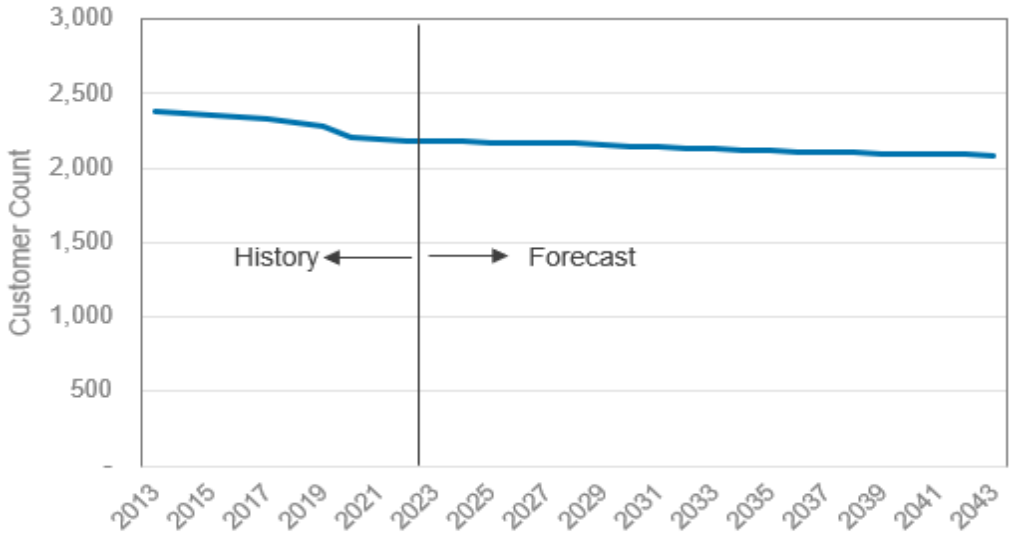


Figure 3-5: NIPSCO Industrial Customer Count Forecast



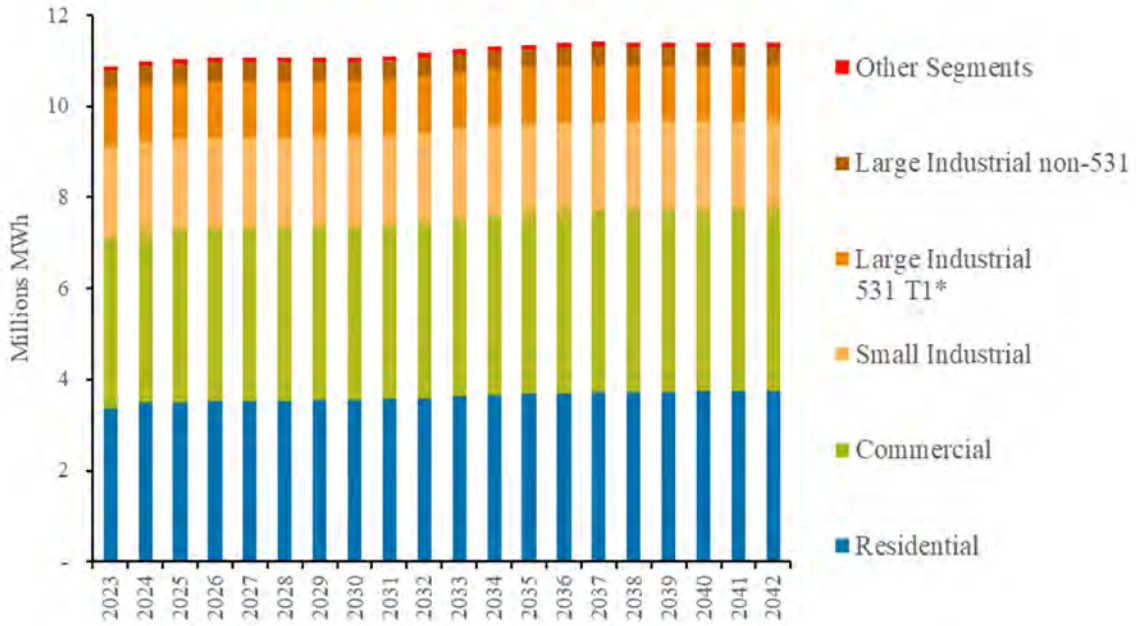
3.3.4 Sales per Customer and Total Electric Sales Forecast

To obtain the total monthly energy sales forecast for each class between 2024 and 2043, the energy sales per customer forecast is multiplied by the customer count forecast. Figure 3-6 presents NIPSCO's projected electric energy sales forecast by customer class and total NIPSCO energy sales through 2043,[20] *prior to any adjustments for EVs, DERs, and large economic development loads*, which are described later in this section.[21] The CAGR for residential customers is projected to be 0.37%, the CAGR for commercial energy sales is projected to be 0.36%, while the CAGR for the industrial class is projected to be -0.15% between 2024 and 2043.

[20] Note that "Other" includes Railroad, Street Lighting, Public Authority, and Company Use. Note that losses are calculated monthly to arrive at net energy for load that must be served by generation. Losses are approximately 4.62% on a monthly basis.

[21] Note that these summaries also do not include the impact of transmission and distribution system losses, which are included in the final forecasts presented later in this Section.

Figure 3-6: NIPSCO Electric Sales Forecast by Customer Class before Adjustments and Excluding Losses (MMWh)



3.3.5 Peak Load Forecast Development

After developing the baseline energy forecasts, NIPSCO developed peak load forecasts on a monthly basis. NIPSCO's historical sample meter data was used to develop the monthly peak load factors for the residential, commercial, and small industrial customer classes, as presented in Figure 3-7. Based on the sample data, peak load factors are lowest during summer months including June, July, and August and higher during winter months including January, February and December. The formula used to develop load factors is summarized in Equation 3-3, and the summer and winter peak load forecasts by customer class, *prior to any adjustments for EVs, DERs, and large economic development loads,* which are described later in this Section, are shown in Figure 3-8 .

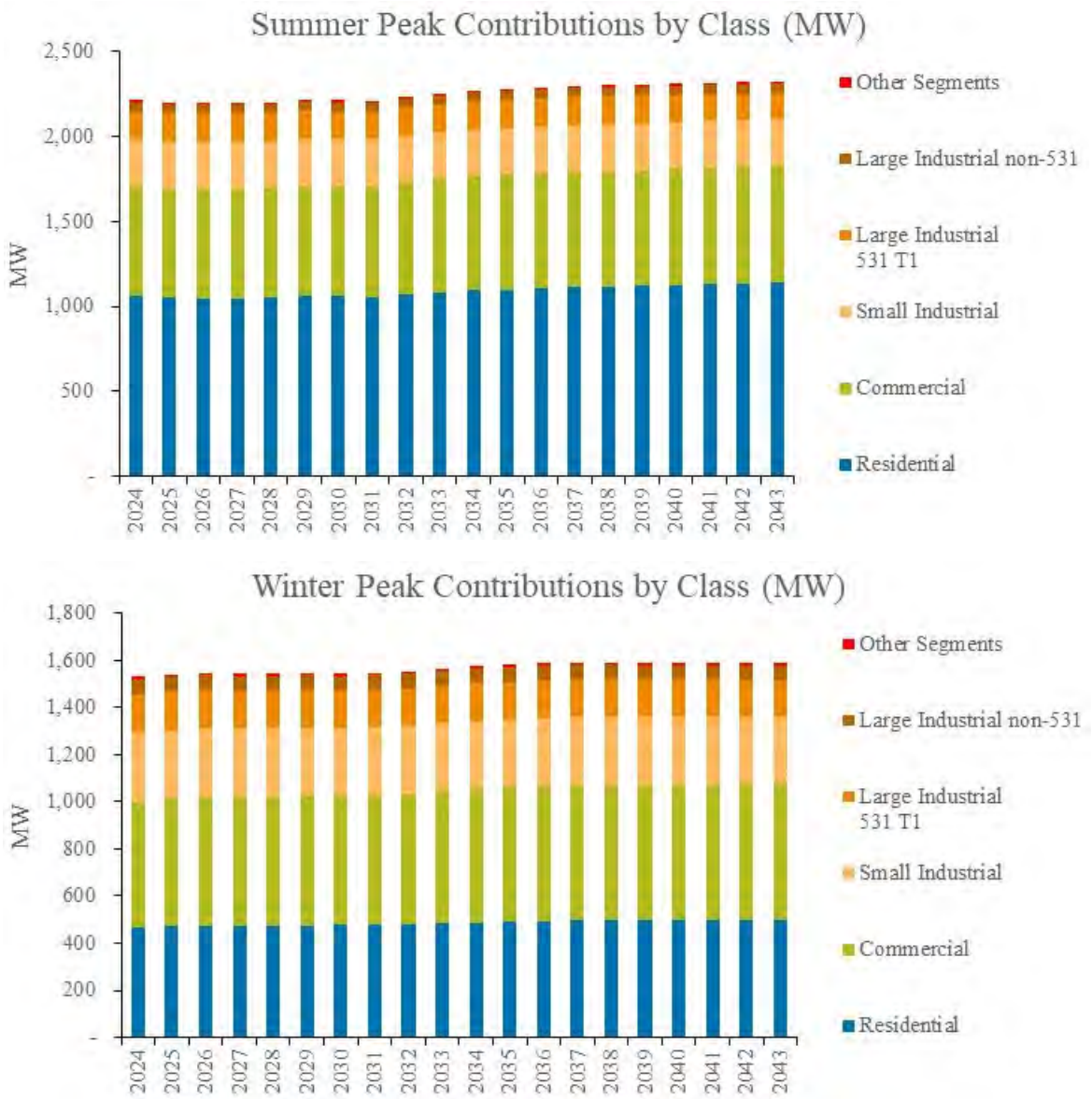
Equation 3-3: Load Factor Calculation

$$Load\ Factor = \left(\frac{Usage\ (kWh)}{\left(Demand\ kW\ *\ 24 \frac{hr}{day} * X \frac{days}{mo} \right)} \right)$$

Figure 3-7: Calculated Peak Load Factors by Customer Class

Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	88.88%	88.88%	88.88%	69.90%	69.90%	51.60%	51.60%	51.60%	51.60%	69.90%	88.88%	88.88%
Commercial	81.60%	81.60%	81.60%	75.30%	75.30%	75.40%	75.40%	75.40%	75.40%	75.30%	81.60%	81.60%
Industrial	83.60%	83.60%	83.60%	80.80%	80.80%	83.00%	83.00%	83.00%	83.00%	83.00%	83.60%	83.60%

Figure 3-8: Seasonal NIPSCO Peak Load Forecast by Customer Class before Adjustments and Excluding Losses



3.4 Electric Vehicles

3.4.1 Methodology Overview

NIPSCO developed a range of potential EV penetration rates based on existing data regarding ICE vehicle and EV counts in NIPSCO counties and a top-down forward-looking outlook based on analysis of third-party projections, policy goals, and current trends. NIPSCO-specific and external information about electricity charging usage and hourly charging patterns was then used to estimate the impact on NIPSCO sales and peak load requirements for each of the market scenarios.

The EV analysis was broken down different classes of vehicles and charging locations, which were independently forecasted:

- LDVs in service territory;
- MDVs, including transit vehicles, such as buses and shuttle vans, in service territory;
- Highway corridor charging for HDVs and MDVs

3.4.2 Core Data Source Inputs

3.4.2.1 Starting Vehicle Count Estimates

NIPSCO developed estimates of the starting values for vehicle counts from the following major sources:

- LDVs and MDVs: Indiana Vehicle Fuel Dashboard data
- Transit vehicles: 2022 National Transportation Database
- Corridor charging data: DOT –HPMS

3.4.2.2 Vehicle Count Growth Rate Projections

NIPSCO developed an econometric forecast model to develop EV growth estimates based on adoption rates applied to a sigmoid growth curve. Historical EV registrations were analyzed to create a view of EV adoption in historical years and expected 2024 adoption. Historical ICE registration data was used to obtain a view of total vehicle registrations, and the total number of vehicles was kept constant over time. The inflection year, maximum EV adoption by 2045, and the k value (slope) of the sigmoid curve function were varied across scenario based on analysis of third-party projections, policy goals, and current trends. These assumptions are provided in Table 3-1 and Table 3-2.

Table 3-1: LDV EV Sales Assumptions by Scenario

	Inflection Year	Target EV Adoption as % of LDV Sales by 2045	K Value
Low	2035	50%	0.4
Med	2032	80%	0.45
High	2031	95%	0.5

Table 3-2: MDV and Transit EV Sales Assumptions by Scenario

	Inflection Year	Target EV Adoption as % of MDV Sales by 2045	K Value
Low	2032	30%	0.9
Med	2032	75%	0.9
High	2030	95%	0.9

3.4.3 Light Duty Vehicles

3.4.3.1 LDV EV Growth Forecast

NIPSCO utilized the Indiana Office of Energy Development Vehicle Fuel Dashboard to determine the existing number of electric vehicles registered in the state. The Indiana Vehicle Fuel Dashboard is designed to provide public information about the types of vehicle fuels in the state and trends over time. The dashboard allows users to explore Indiana BMV registration data from January 2018 to present. NIPSCO found that by Jan. 1, 2024, there were approximately 2,015 LDV electric vehicles registered in the service territory. Estimated LDV numbers by County are provided in Table 3-3 and Table 3-4:.

Using the 2023 count of vehicles as a starting number of EV registrations in NIPSCO service territory as of Jan. 1, 2024, the annual sales of light duty vehicles were forecasted to grow as detailed in Table 3-1. NIPSCO took an average of total LDV vehicle registrations between 2018 and 2023 to find a total of approximately 644 thousand LDVs, data detailed in Table 3-5:. This average number of LDVs was kept constant throughout the forecast period.

The replacement of older, less efficient vehicles is assumed to naturally occur as vehicles age and owners adopt new vehicle models. To reflect this process of stock turnover, an average car lifetime of 15 years was assumed. The combination of new BEV and PHEV sales per year, as well as the retirement of the existing stock, resulted in fleet-wide projections for BEVs and PHEVs.

Table 3-3: Electric and Hybrid Light Duty Vehicle Registrations in NIPSCO Counties[22]

County	Electric						Electric and Gas Hybrids					
	2018	2019	2020	2021	2022	2023	2018	2019	2020	2021	2022	2023
Benton	1	1	1	1	3	9	14	16	19	28	38	58
Carroll	-	-	-	-	3	11	51	54	56	78	106	129
DeKalb	2	2	3	9	11	25	105	99	110	158	188	237
Elkhart	17	22	33	66	105	183	720	747	815	1,057	1,283	1,570
Fulton	-	-	1	4	10	18	51	43	57	54	77	106
Jasper	-	-	2	9	14	25	67	76	82	126	138	199
Kosciusko	3	3	7	18	37	78	298	324	346	460	581	684
LaGrange	1	1	-	5	10	11	55	60	70	103	125	141
Lake	18	42	72	215	417	794	1,455	1,454	1,597	2,195	2,798	3,715
LaPorte	11	12	24	44	73	122	317	314	330	472	563	748
Marshall	1	1	1	6	20	31	134	149	152	217	269	327
Newton	-	-	-	1	2	5	34	29	30	45	58	71
Noble	1	1	-	8	18	21	90	83	93	127	170	208
Porter	23	26	48	103	214	385	784	803	866	1,156	1,145	1,918
Pulaski	1	-	1	2	5	1	24	21	18	28	35	40
St. Joseph	19	29	48	111	224	379	1,247	1,314	1,492	1,831	2,232	2,753
Starke	-	1	1	2	5	4	48	49	43	72	77	112
Steuben	3	4	4	10	19	23	108	117	121	172	219	284
White	1	1	1	9	16	27	65	58	60	86	115	154
Total	102	146	247	623	1,206	2,152	5,667	5,810	6,357	8,465	10,217	13,454

[22] Indiana Office of Energy Development, Indiana Vehicle Fuel Dashboard, accessed Jan. 11, 2024. Electric and Gas Hybrid counts include non-plug-in hybrids. County vehicle counts are not representative of the NIPSCO service territory. https://www.in.gov/oed/resources-and-information-center/vehicle-fuel-dashboard/

Table 3-4: Estimated EVs in NIPSCO Service Territory[23]

County	% Households in NIPSCO Service Territory	2018	2019	2020	2021	2022	2023
Benton	100%	2	2	2	3	5	12
Carroll	77%	2	2	3	4	7	14
DeKalb	17%	1	1	2	3	4	7
Elkhart	57%	35	38	47	74	105	159
Fulton	55%	2	1	2	4	8	13
Jasper	82%	3	4	6	14	18	30
Kosciusko	58%	12	13	16	27	42	70
LaGrange	52%	2	2	2	6	9	10
Lake	100%	105	129	168	347	585	1,017
LaPorte	100%	30	31	44	72	107	167
Marshall	36%	3	4	4	7	13	18
Newton	65%	1	1	1	2	4	6
Noble	6%	0	0	0	1	2	2
Porter	91%	64	68	91	158	258	457
Pulaski	47%	1	1	1	2	3	2
St. Joseph	0%	0	0	0	0	1	1
Starke	3%	0	0	0	0	0	0
Steuben	67%	6	7	8	14	21	27
White	5%	0	0	0	1	1	2
Total	-	272	306	397	737	1,193	2,015

[23] Estimated count of electric vehicles in the NIPSCO service territory is determined by the approximate % of households within the country that fall into NIPSCO service territory. The Electric and Gas hybrid category is assumed to be predominantly non-plug-in hybrids based on analysis of hybrid vehicle types. NIPSCO assumes 6% of Electric and Gas hybrids are plug-in electric hybrids.

Table 3-5: Estimated Total LDVs in NIPSCO Service Territory[24]

County	2018	2019	2020	2021	2022	2023
Benton	6,659	6,710	6,583	6,662	6,658	6,614
Carroll	15,752	15,883	15,749	16,147	15,781	16,003
DeKalb	30,804	31,072	31,381	32,065	31,782	32,128
Elkhart	121,397	122,113	122,107	126,259	123,869	124,125
Fulton	15,068	15,065	14,969	15,216	15,185	15,031
Jasper	24,705	24,961	24,615	25,669	25,217	25,542
Kosciusko	53,812	54,281	53,587	55,122	54,495	54,503
LaGrange	20,567	20,488	20,252	21,192	20,648	20,474
Lake	261,456	262,859	258,449	267,672	262,950	264,550
LaPorte	73,125	72,880	72,329	73,906	72,083	72,614
Marshall	31,769	31,979	31,572	32,512	32,273	32,136
Newton	11,163	11,107	10,814	11,206	10,880	10,880
Noble	33,111	33,170	33,480	34,425	33,966	33,825
Porter	105,597	105,964	10,4951	108,077	107,414	108,048
Pulaski	10,065	10,087	9,891	10,307	10,050	10,181
St. Joseph	148,686	149,829	148,934	151,421	149,359	150,223
Starke	17,681	17,442	17,316	17,893	17,625	17,768
Steuben	25,323	26,115	25,917	26,586	25,977	26,175
White	18,829	19,305	19,048	19,487	19,126	19,145
Total	639,562	642,705	635,213	655,478	644,701	647,984

[24] Indiana Office of Energy Development, Indiana Vehicle Fuel Dashboard accessed Jan. 11, 2024. https://www.in.gov/oed/resources-and-information-center/vehicle-fuel-dashboard/

Figure 3-9: LDV EV Adoption: EVs as a % of new LDV sales

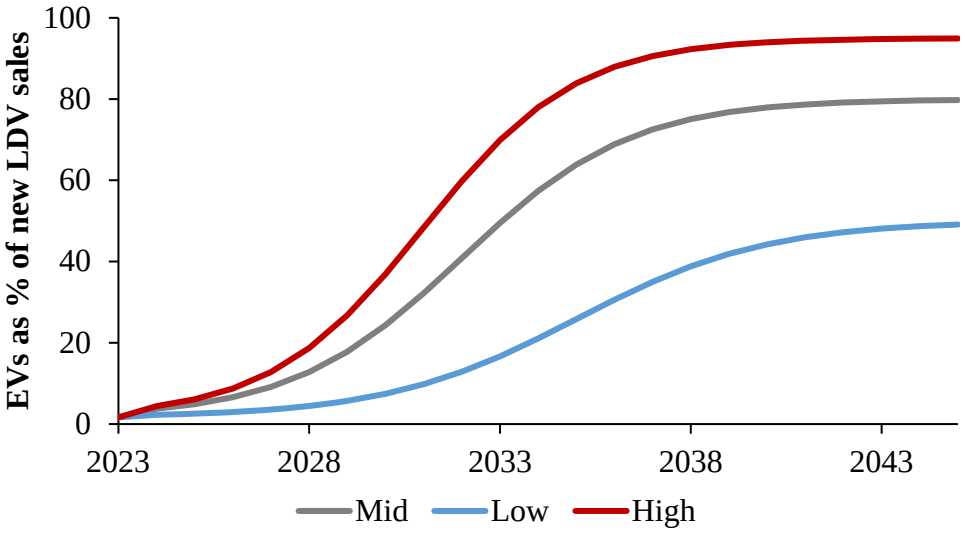
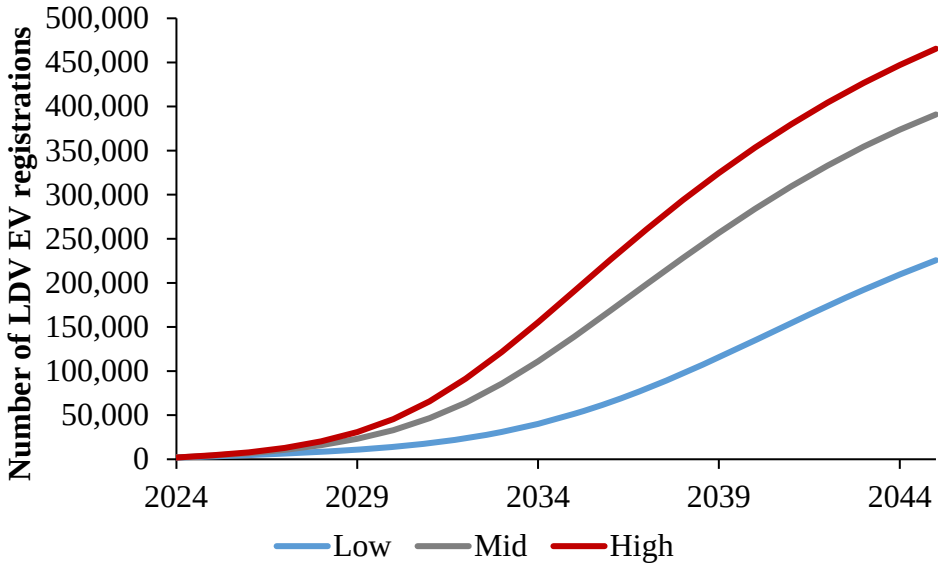


Figure 3-10: LDV EV Adoption: Number of EVs registered in NIPSCO service territory[25]



[25] NIPSCO assumes an average LDV lifetime of 12 years based on Bureau of Transportation data. As the makeup of the existing fleet age is unknown, the historical registration data is evenly distributed over the 12-year assumed lifetime to factor in retirements for the fleet turnover analysis. https://www.bts.gov/content/average-age-automobiles-and-trucks-operation-united-states

3.4.3.2 LDV EV Energy Use

NIPSCO utilized the EVI-Pro-Lite[26] tool from the National Renewable Energy Lab to develop hourly vehicle charging shapes and resulting energy use from EV charging. NIPSCO developed three main charging shapes to represent an hourly weather-adjusted 2024 ("Today") charging profile, a 2030 charging profile, and a 2040 charging profile. The EVI-Pro-Lite tool allows the user to specify a number of inputs, including:

- **Fleet size:** This input is not utilized directly as results are normalized to inflate by the number of vehicles shown in Figure 3-10.
- **Average daily miles traveled per vehicle:** Detailed in Table 3-8.
- **Average ambient temperature:** NIPSCO uses an average daily temperature based on historical weather data.
- **Mix of vehicles that are fully electric:** NIPSCO assumes a plug-in electric vehicle focused distribution of vehicles, detailed in Table 3-7.
- **Share of electric vehicles that are sedans vs. SUVs:** NIPSCO assumes relatively even distribution of sedan and SUV vehicles, detailed in Table 3-7.
- **Share of Level 1 and Level 2 workplace charging:** Assumed to evolve over time.
- **Share of electric vehicles with access to home charging:** NIPSCO assumes that 100% of electric vehicles will have access to home charging as much of the service territory falls in residential areas. This could be Level 1 or Level 2 charging.
- **Vehicle preference for home charging:** NIPSCO assumes that 100% of electric vehicles will prefer home charging if they have access to a charger.
- **Home charging strategy** (immediate, delayed, etc.)
- **Workplace charging strategy** (immediate, delayed, etc.)

[26] NREL and DOE EVI-Pro-Lite https://afdc.energy.gov/evi-x-toolbox#/evi-pro-ports

Figure 3-11: LDV assumptions evolution over time

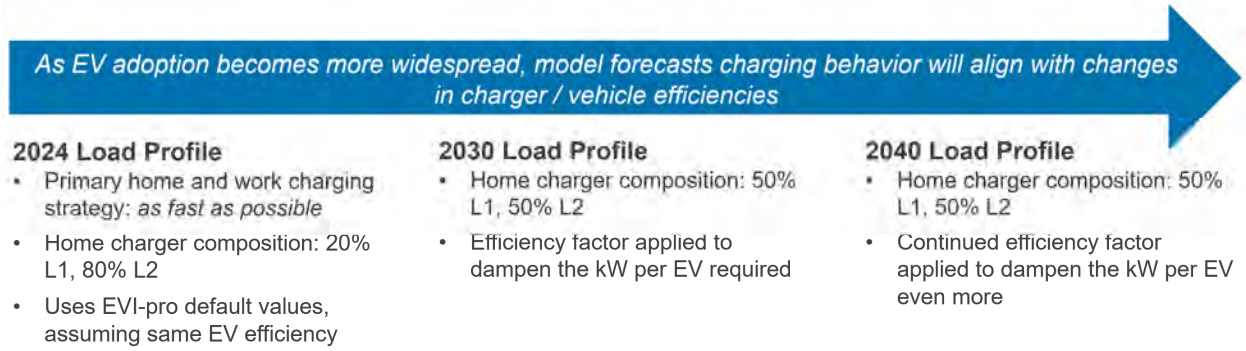


Table 3-6: Assumed efficiency of LDV vehicle types (miles/kWh)[27]

EV Type	2024-2029	2030-2039	2040-2045
BEV Sedan	2.57	3.5	5.0
BEV SUV	2.3	3.0	4.5
PHEV Sedan	2.95	4.0	5.0
PHEV SUV	2.4	3.25	4.5

Table 3-7: Vehicle type market share assumptions (share of EVs adopted by year)

EV Type	2024-2029	2030-2039	2040-2045
BEV Sedan	44%	50%	52%
BEV SUV	36%	41%	43%
PHEV Sedan	14%	7%	4%
PHEV SUV	6%	3%	2%

Table 3-8: Vehicle miles traveled per day[28]

	2024-2029	2030-2039	2040-2045
VMT	27.5	33.75	40.0

Sample LDV weekday and weekend charging profiles are detailed in Figure 3-12 through Figure 3-17. EV charging profiles are blended over the forecast horizon to create hourly EV charging profiles that consider ambient temperature, day of week, number of vehicles, type of charger (level and location, and vehicle mix).

27 https://atb.nrel.gov/electricity/2022/index

28 https://www.sciencedirect.com/science/article/abs/pii/S254243512300404X

Figure 3-12: LDV EV 2024 Weekday Charging Profile (kW/vehicle)

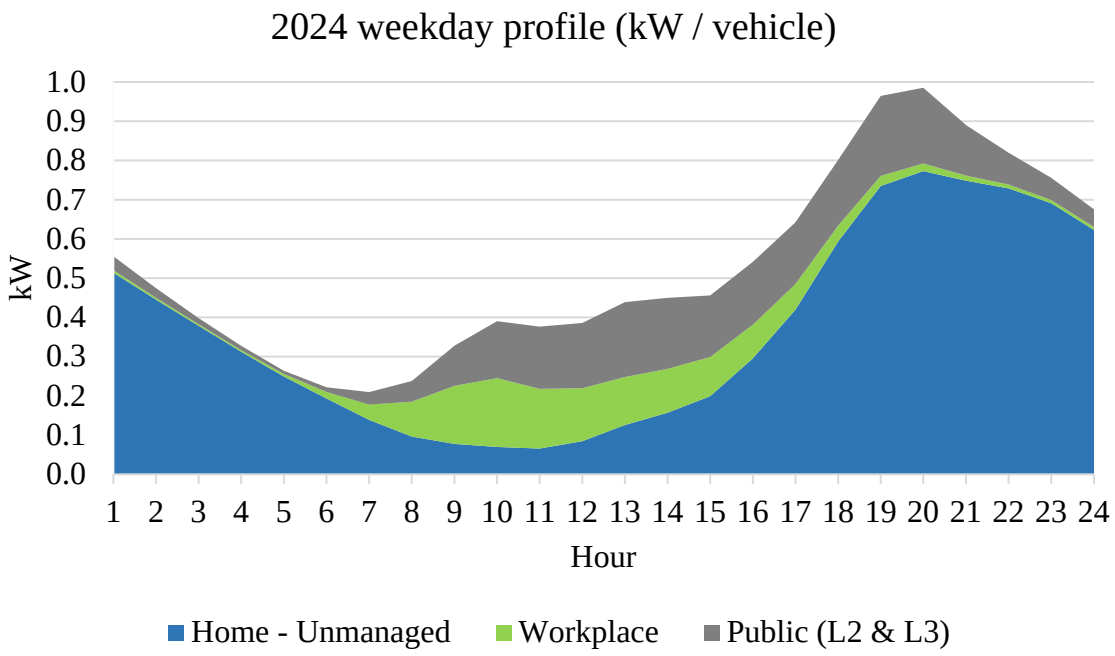


Figure 3-13: LDV EV 2024 Weekend Charging Profile (kW/vehicle)

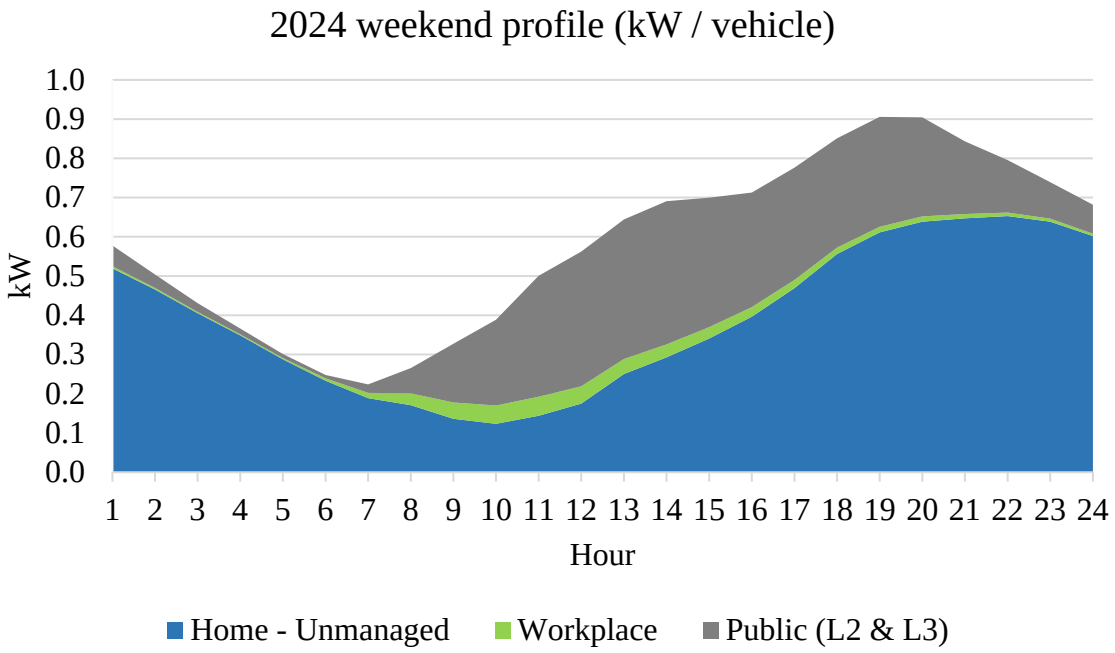


Figure 3-14: LDV EV 2030 Weekday Charging Profile (kW/vehicle)

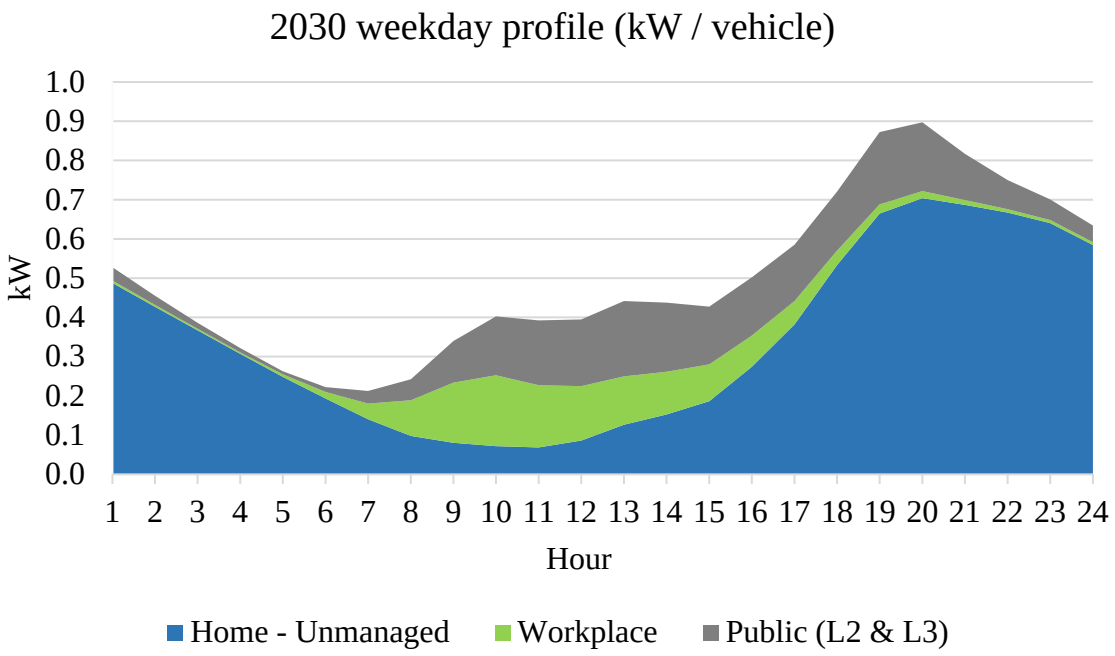


Figure 3-15: LDV EV 2030 Weekend Charging Profile (kW/vehicle)

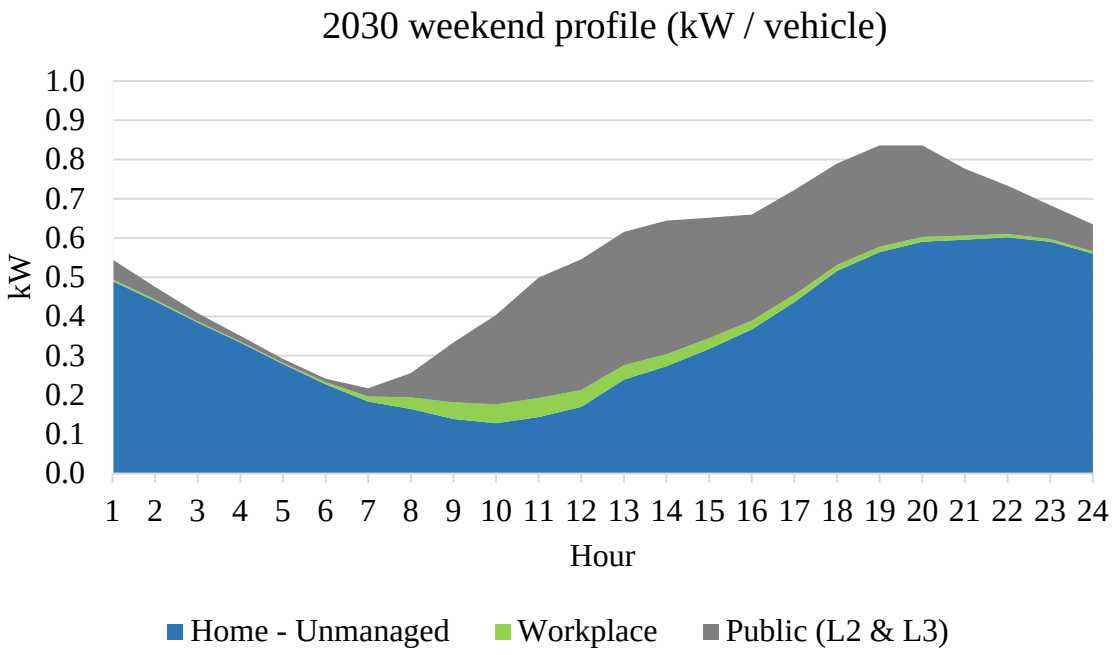


Figure 3-16: LDV EV 2040 Weekday Charging Profile (kW/vehicle)

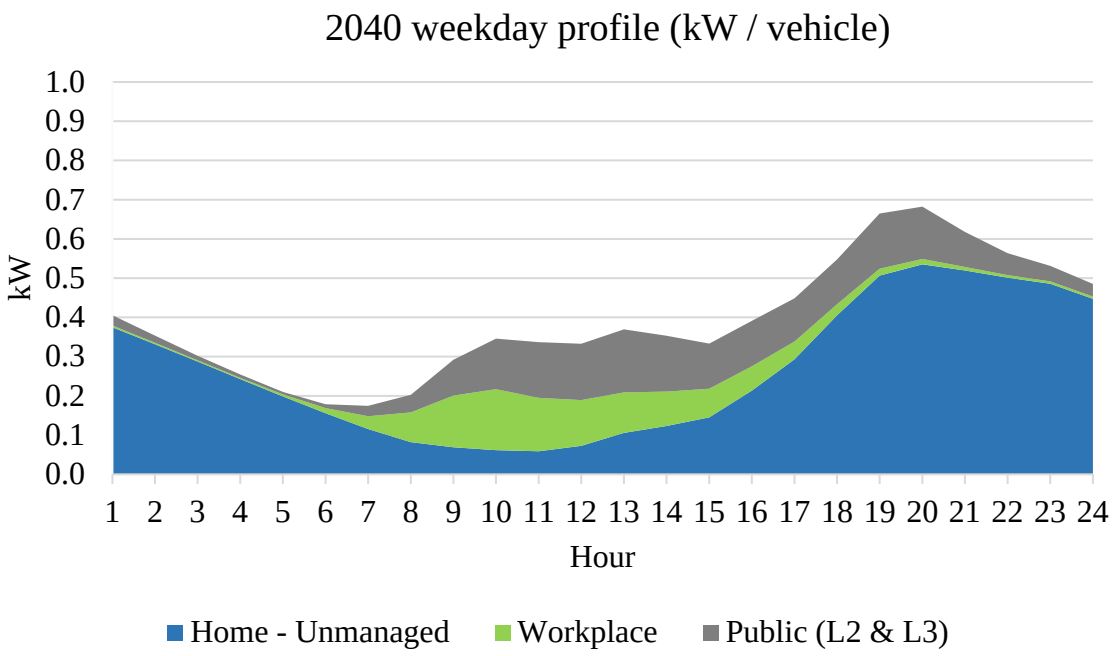
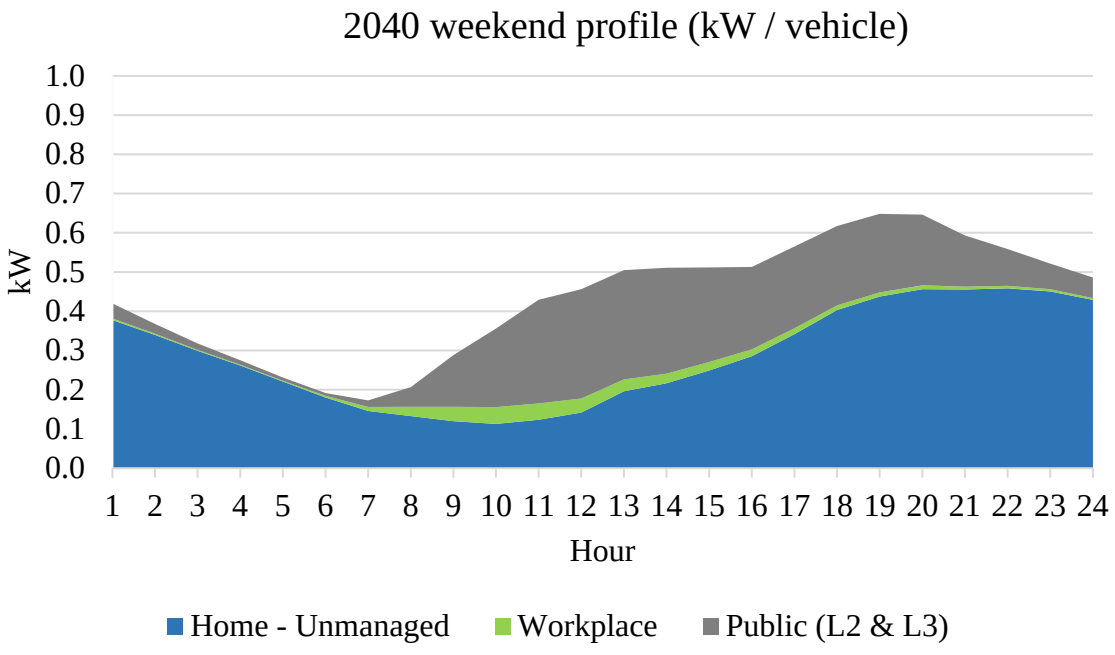


Figure 3-17: LDV EV 2040 Weekend Charging Profile (kW/vehicle)



3.4.4 MDV and Transit Vehicles

3.4.4.1 MDV and Transit EV Growth Forecast

A similar approach was used for estimating fleet wide vehicle numbers, which includes buses, cutaway vans, and shuttles. The MDV EV growth forecast used the same approach as was used for LDVs in Section 3.4.3.1. The historical MDV vehicle count by county and NIPSCO service territory are detailed in Table 3-9 and Table 3-10.

Table 3-9: All MDV Vehicles in NIPSCO Service Territory[29]

County	2018	2019	2020	2021	2022	2023
Benton	206	217	248	276	274	307
Carroll	495	530	536	602	629	686
DeKalb	812	852	892	1,043	1,033	1,123
Elkhart	3,409	3,415	3,624	3,900	3,843	4,228
Fulton	455	486	533	580	591	653
Jasper	755	752	816	916	957	1,109
Kosciusko	1,518	1,541	1,703	1,740	1,841	1,960
LaGrange	775	815	893	959	1,004	1,072
Lake	4,824	5,093	5,228	5,630	5,562	6,170
LaPorte	1,714	1,765	1,918	2,047	2,030	2,317
Marshall	994	1,032	1,140	1,333	1,276	1,306
Newton	279	308	334	377	410	454
Noble	961	1,030	1,077	1,205	1,228	1,333
Porter	1,938	2,087	2,175	2,406	2,420	2,673
Pulaski	323	325	341	377	391	416
St. Joseph	2,946	3,092	3,224	3,475	3,315	3,559
Starke	457	472	482	510	531	573
Steuben	750	744	782	860	917	966
White	533	558	640	676	678	835
Total	14,446	15,035	15,875	17,220	17,302	19,105

[29] Indiana Office of Energy Development, Indiana Vehicle Fuel Dashboard accessed Jan. 11, 2024. County vehicle counts are not representative of the NIPSCO service territory. MDVs are distributed using determined by the approximate % of households within the country that fall into NIPSCO service territory. See Table 3-4:. https://www.in.gov/oed/resources-and-information-center/vehicle-fuel-dashboard/

Table 3-10: MDV EVs and Total MDVs in NIPSCO Service Territory

Year	Electric	E&G Hybrid	Total
2018	0	0	14,446
2019	0	0	15,035
2020	0	0	15,875
2021	0	0	17,220
2022	2	0	17,302
2023	8	0	19,105

Limited data is available on the adoption of electric transit vehicles within NIPSCO's service territory. To estimate the total number of transit vehicles in NIPSCO counties, data was developed from the 2022 National Transit Database, the Federal Transit Administration's repository of data on financial, operating, and asset conditions of American transit systems. Filtering on NIPSCO counties, there were approximately 471 transit vehicles registered, with 267 estimated to be within the NIPSCO service territory, as summarized in Table 3-9 and Table 3-12. As there is no data for electric transit vehicles, NIPSCO starts with fully internal combustion engines for all transit.

From the National Transit Database, an average lifetime for each vehicle type was determined, detailed in Table 3-13. This data point is consistent with the idea that higher utilization leads to shorter lifetimes, when compared to the lifespan of LDV passenger light-duty vehicles. Forecasts of electric MDVs and transit vehicles were developed using the sigmoid growth curve described in Section 3.4.2.2. See Table 3-2 for assumptions. The EV MDV and transit adoption profiles by scenario are detailed in Figure 3-18. Final MDV and transit EV vehicle counts are shown in Figure 3-19 and Figure 3-20, respectively.

Table 3-11: All Transit Vehicles in NIPSCO Counties[30]

County	Bus	Cutaway	Minivan	Over-the-road Bus	Steel Wheel Vehicles	Trucks and other Rubber Tire Vehicles	Van
Benton	0	0	0	0	0	0	0
Carroll	0	0	0	0	0	0	0
DeKalb	0	3	8	0	0	0	0
Elkhart	0	0	0	0	0	0	0
Fulton	0	2	9	0	0	0	0
Jasper	0	0	0	0	0	0	0
Kosciusko	0	11	1	0	0	0	0
LaGrange	0	8	5	0	0	0	0
Lake	28	34	0	0	0	8	1
LaPorte	0	19	0	0	0	1	0
Marshall	0	2	8	0	0	0	0
Newton	0	0	0	0	0	0	0
Noble	0	2	9	0	0	0	6
Porter	0	33	1	5	18	93	1
Pulaski	0	0	0	0	0	0	0
St. Joseph	62	23	10	0	0	7	0
Starke	0	0	0	0	0	0	0
Steuben	0	9	6	0	0	0	0
White	0	15	23	0	0	0	0
Total	90	161	80	5	18	109	8

[30] Federal Transit Administration, The 2022 National Transit Database. https://www.transit.dot.gov/ntd

Table 3-12: Estimated Transit Vehicles in NIPSCO Service Territory[31]

County	% Households in NIPSCO Service Territory	Bus	Cutaway	Minivan	Over-the-road Bus	Steel Wheel Vehicles	Trucks and other Rubber Tire Vehicles	Van
Benton	100%	0	0	0	0	0	0	0
Carroll	77%	0	0	0	0	0	0	0
DeKalb	17%	0	1	1	0	0	0	0
Elkhart	57%	0	0	0	0	0	0	0
Fulton	55%	0	1	5	0	0	0	0
Jasper	82%	0	0	0	0	0	0	0
Kosciusko	58%	0	6	1	0	0	0	0
LaGrange	52%	0	4	3	0	0	0	0
Lake	100%	28	34	0	0	0	8	1
LaPorte	100%	0	19	0	0	0	1	0
Marshall	36%	0	1	3	0	0	0	0
Newton	65%	0	0	0	0	0	0	0
Noble	6%	0	0	1	0	0	0	0
Porter	91%	0	30	1	5	16	85	1
Pulaski	47%	0	0	0	0	0	0	0
St. Joseph	0%	0	0	0	0	0	0	0
Starke	3%	0	0	0	0	0	0	0
Steuben	67%	0	6	4	0	0	0	0
White	5%	0	1	1	0	0	0	0
Total	-	28	103	19	5	16	94	2

Table 3-13: Estimated Transit Vehicle Age[32]

Transit Vehicle Type	Average Fleet Age (years)
Bus	7.0
Cutaway	5.0
3-13	5.7
Over-the-road Bus	11.4
Steel Wheel Vehicles (Service)	12.9
Trucks and other Rubber Tire Vehicles (Service)	5.7
Van (MDV)	10.8

[31] Estimated count of transit vehicles in the NIPSCO service territory is determined by the approximate % of households within the country that fall into NIPSCO service territory.

Figure 3-18: MDV and Transit EV Adoption: EVs as a % of new sales

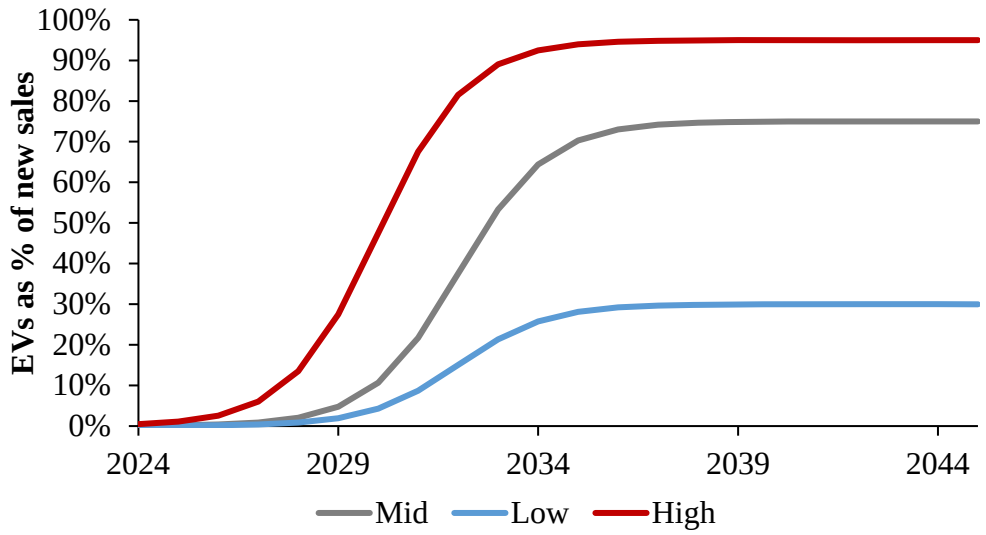
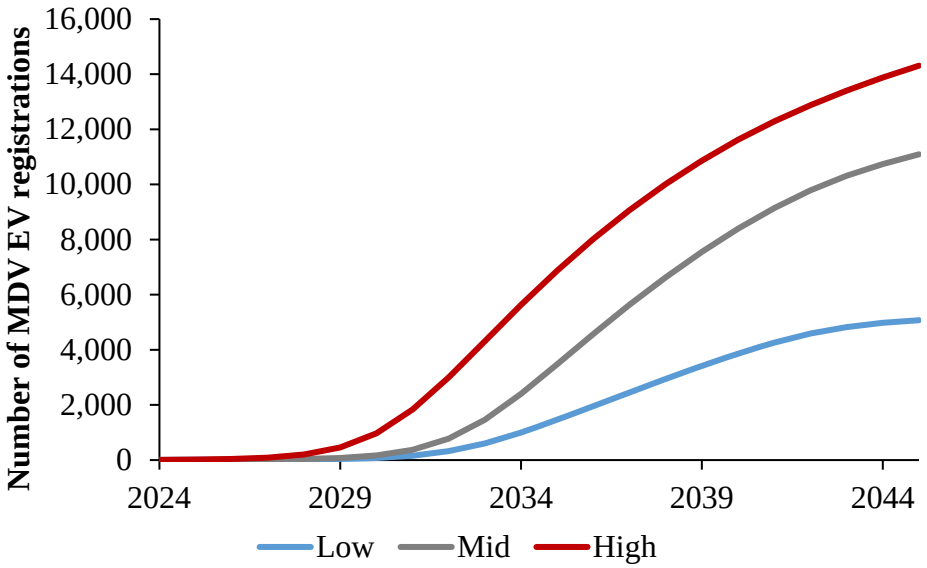
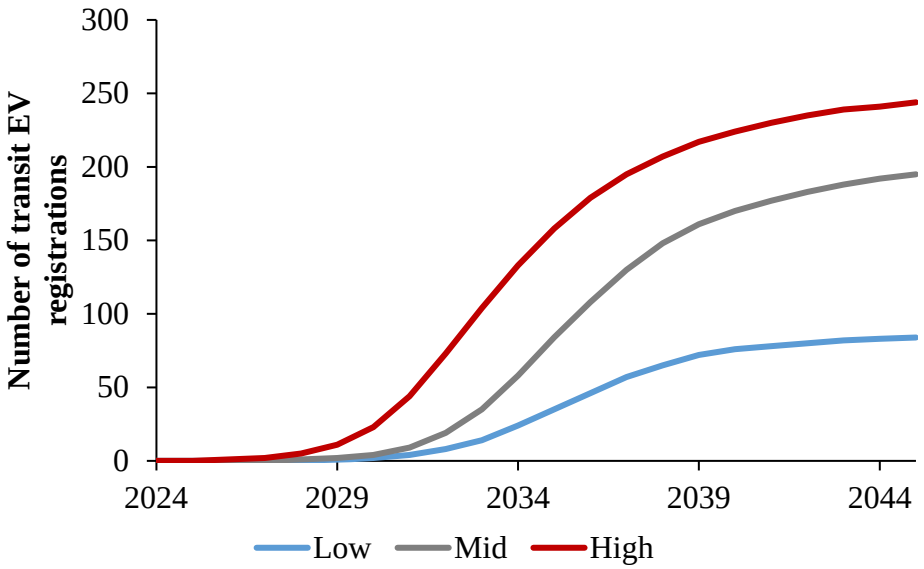


Figure 3-19: MDV EV Adoption: Number of EVs registered in NIPSCO service territory[33]



[33] See Table 3-13 for fleet age assumptions. As the makeup of the existing fleet age is unknown, the historical registration data is evenly distributed over the fleet age assumed lifetime to factor in retirements for the turnover analysis.

Figure 3-20: Transit EV Adoption: Number of EVs registered in NIPSCO service territory[34]



3.4.4.2 MDV and Transit EV Energy Use

NIPSCO utilized MDV and transit charging shapes based on a 2016 NREL Study of MDV Electric Delivery Trucks[35] depicted as the "unmanaged" shape in Figure 3-21. This unmanaged shape is used from 2024 through 2030, when a blend of managed charging loads begins to emerge, based on the assumption that time-of-use rates and managed charging infrastructure will begin to displace unmanaged behavior in later years. The managed charging shape was adapted from recent data releases from California IRP proceedings, based on 2021 study from Berkeley Lab.[36] This approach assumes the adoption of TOU rates and managed charging approaches and is used as a baseline future projection for how MDV loads may balance from 2030 to 2045, although some degree of unmanaged charge remains for duration of forecast period. Vehicle efficiency and vehicle miles traveled assumptions are detailed in Table 3-14 and Table 3-15, respectively. Ambient temperature adjustments to the charging profiles are detailed in Table 3-16.

[34] See Table 3-13 for fleet age assumptions. As the makeup of the existing fleet age is unknown, the historical registration data is evenly distributed over the fleet age assumed lifetime to factor in retirements for the turnover analysis.

[35] https://www.nrel.gov/docs/fy17osti/66382.pdf

[36] https://www.energy.ca.gov/sites/default/files/2021-09/5%20LBNL-FTD-EAD-HEVI-LOAD%20Medium-%20and%20Heavy-Duty%20Load%20Shapes_ADA.pdf

Figure 3-21: MDV and Transit EV Charging Shapes

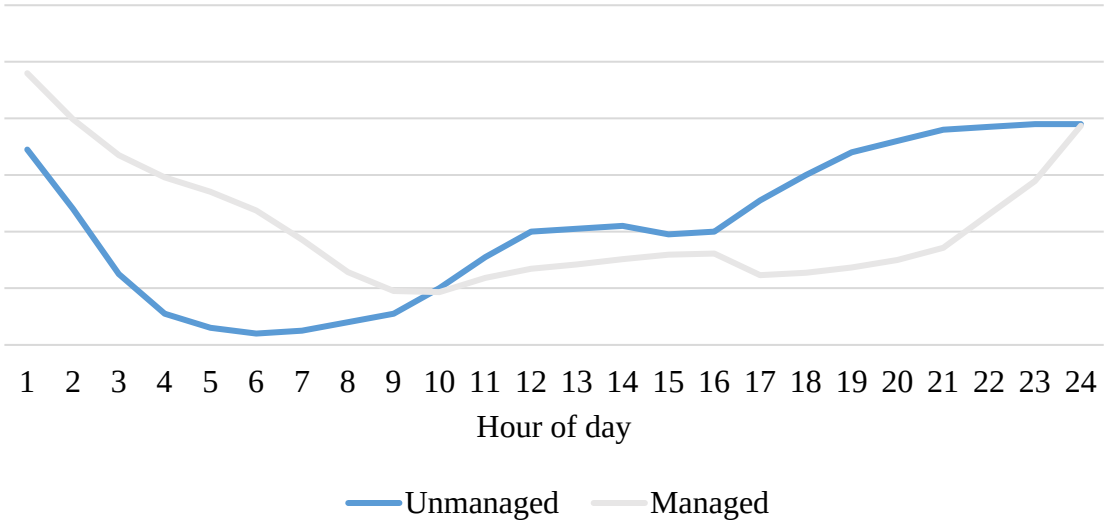


Table 3-14: Assumed Efficiency of MDV And Transit Vehicle Types (kWh/mile)[37]

EV Type	2020	2025	2030	2035	2040	2045	2050
Step Van (MDVs)	1.38	1.27	1.16	1.06	1.03	0.99	0.96
Box Truck	1.45	1.33	1.23	1.13	1.09	1.06	1.02
Bus	3.10	2.84	2.60	2.38	2.30	2.23	2.16
Cutaway	0.49	0.45	0.41	0.38	0.36	0.35	0.34
Minivan	0.49	0.45	0.41	0.38	0.36	0.35	0.34
Over-the-road Bus	3.10	2.84	2.60	2.38	2.30	2.23	2.16
Steel Wheel Vehicles	0.49	0.45	0.41	0.38	0.36	0.35	0.34
Trucks and other Rubber Tire Vehicles	1.12	1.02	0.94	0.86	0.83	0.80	0.78

[37] Assumptions compiled from the following: (1) NREL (2022). 2022 Annual Technology Baseline Transportation Data. (2) MISO (2021) Exploring enhanced load flexibility from grid-connected electric vehicles on the Midcontinent Independent System Operator grid. (3) Characterization of battery electric transit bus energy consumption by temporal and speed variation, published in Energy (2023).

Table 3-15: Vehicle Miles Traveled Per Weekday, Weekend Operation Assumptions[38]

EV Type	Average miles / day	Weekend % of weekday
Step Van (MDVs)	31	75%
Box Truck	45	75%
Bus	119	75%
Cutaway	31	66%
Minivan	31	66%
Over-the-road Bus	119	75%
Steel Wheel Vehicles	31	66%
Trucks and other Rubber Tire Vehicles	75	66%

Table 3-16: Temperature Impact On MDV And Transit Vehicle Miles Traveled[39]

Degree Celsius	MDV % increase in VMT from baseline	Transit % increase in VMT from baseline
-20	30%	42%
-10	20%	38%
0	10%	33%
10	0%	10%
20	0%	0%
30	10%	10%

3.4.5 Heavy-Duty Vehicles

NIPSCO did not assume electrification of native HDVs within the service territory. However, NIPSCO did study truck corridor charging along major roadways within the service territory that included heavy-duty vehicles as a breakout class, as detailed in the next section.

3.4.6 Corridor Charging

In addition to predicting the adoption of EVs for vehicles based in the service territory, NIPSCO explored the potential impact of charging by vehicles that are not based in NIPSCO service territory but travel through the territory via highway corridors. To perform this analysis, NIPSCO contracted with ElectroTempo Inc., a software-based consultancy that specializes in projecting electrical vehicle charging demand and infrastructure. The types of vehicles captured in

[38] U.S. DOE, Average Annual Vehicle Miles Traveled by Major Vehicle Category https://afdc.energy.gov/data/widgets/10309

[39] Information gathered from the U.S. EPA (https://www.epa.gov/system/files/documents/2023-04/elec-schl-bus-cold-weather-consider-2023-04-19.pdf) and the following study: https://www.power.com/community/green-room/blog/impact-climate-range-electric-vehicles

the corridor analysis include delivery trucks and long-haul trucks that choose to exit the highway and recharge within the NIPSCO service territory. This additional charging is counted towards total sales regardless of whether the vehicle starting point or destination falls outside of the service territory.

3.4.6.1 Truck Charging Station Locations, Daily Traffic, and Growth

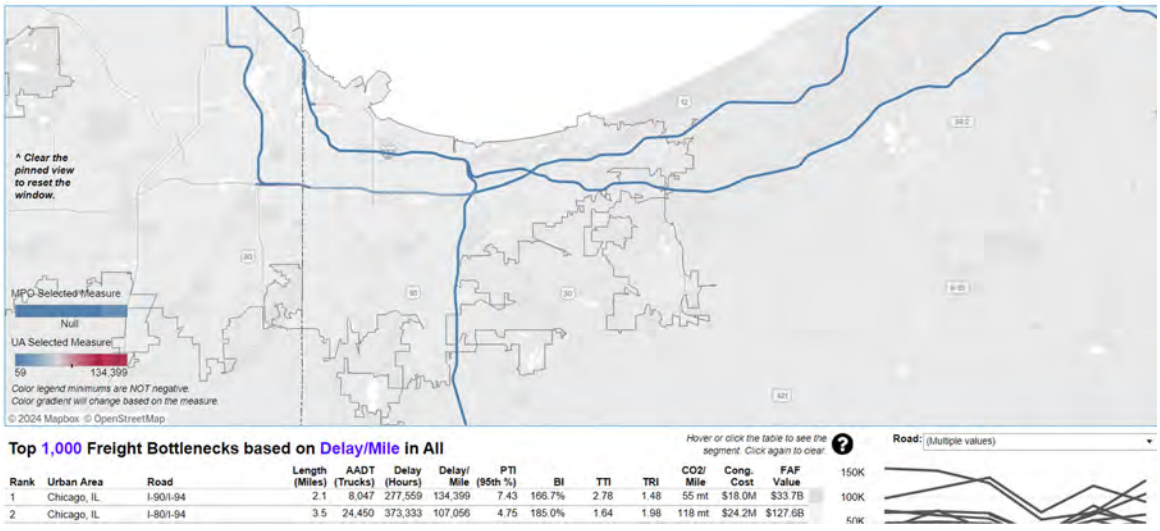
First, NIPSCO identified key traffic corridors within the service territory using Google Maps and satellite imagery. These included I-94, I-90, I-65, I-69, and other state roads (see Table 3-17). Next, NIPSCO located all highway and truck stops with current fueling stations to establish the universe of potential charging locations along the corridors. For this forecast, 43 sites were identified.

Table 3-17: Charging Locations on Each Corridor

Corridor	Sites
I-94	13
State Roads	11
I-90	6
I-65	8
I-69	5
Total	**43**

NIPSCO then estimated daily traffic along the six main corridors using national freight flow surveys and state highway traffic counts reported to the DOT HPMS. From the daily traffic figures, NIPSCO was then able to develop a view of the total daily estimated arrivals at each individual site. Total arrivals in future years were projected from the current estimate through 2035 by applying an annual growth factor based on historical traffic data.

Figure 3-22: DOT HPMS



3.4.6.2 Estimated Electric Vehicle Traffic as Share of Total Traffic

To estimate total relevant vehicle counts by class, NIPSCO applied EV penetration factors that represent the saturation of electric vehicles relative to the total number of vehicles on the road. Using ElectroTempo's EV Growth Simulator, three electric vehicle penetration scenarios were generated to map to NIPSCO's five planning scenarios used throughout this IRP.

The predicted EV saturation for these corridor-based vehicles by 2035 for each class and each scenario is shown in Table 3-18. More detailed saturation trajectories are shown in Figure 3-23 for MDVs and Figure 3-24 for HDVs. The scenarios aim to provide views on lower and higher rates of electrification of the Medium- and Heavy-Duty fleets moving through NIPSCO's service territory in line with NIPSCO's in-service territory analysis, described earlier in this Section. Given the lack of current HDV adoption and additional uncertainty around the future regulatory environment, NIPSCO employed a conservative HDV adoption rate in its reference and low scenarios.

Table 3-18: Predicted EV Saturation by Class and Scenario by 2035

Scenario	MDV	HDV
Low	5%	0%
Ref	14%	2%
High	27%	10%

Figure 3-23: MDV EV Saturation Forecast by Scenario

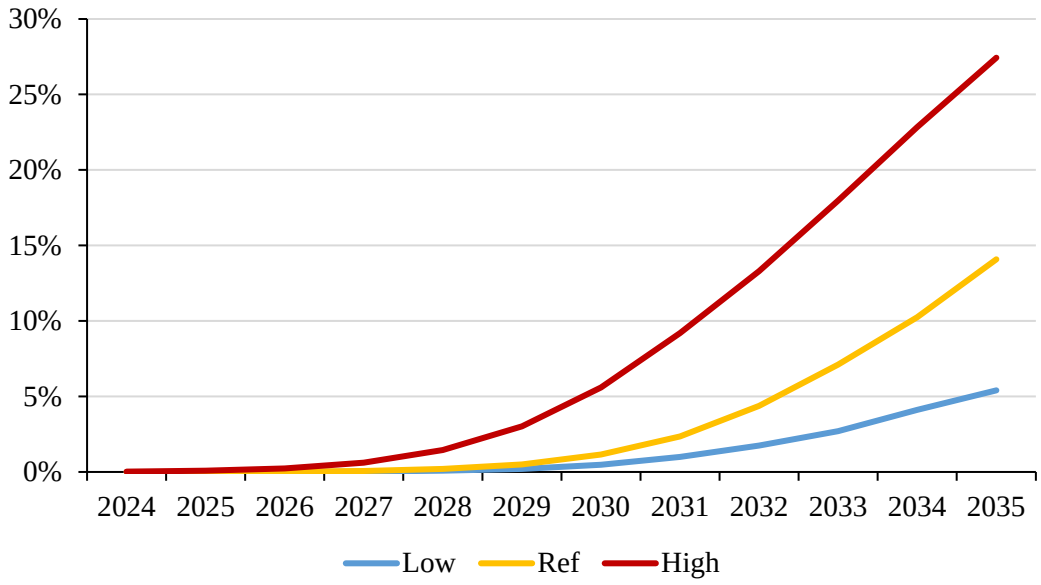
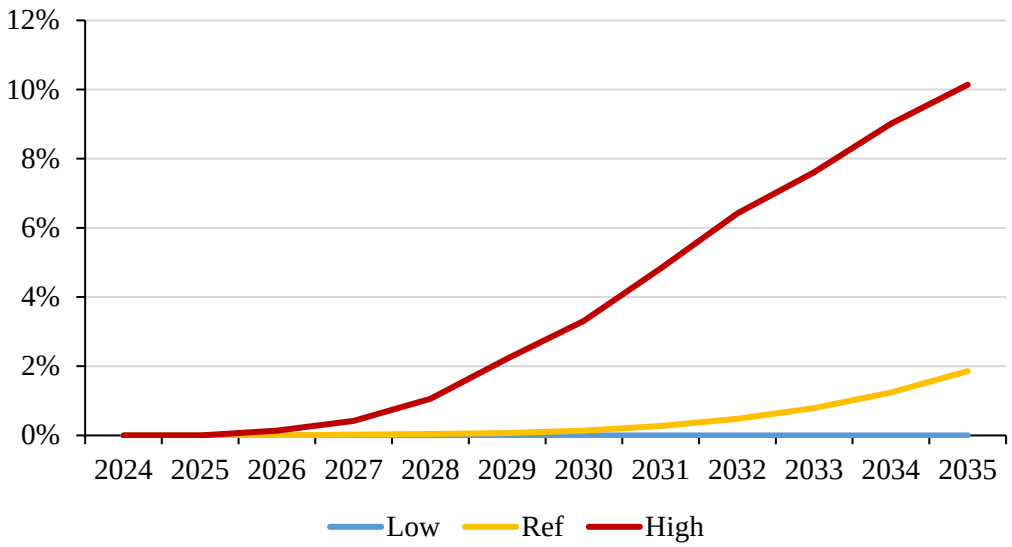


Figure 3-24: HDV EV Saturation Forecast by Scenario



3.4.6.3 Corridor Traffic Patterns and Charging Shape

The total number of EVs stopping at a specific site was calculated using a two-step process. First, the total number of EVs expected to travel by an exit is estimated. Assuming 10% of vehicles choose to stop at an exit,[40] the total daily number of EVs charging at a given exit can be found. Second, the total annual exit charges were divided evenly by the total number of charging sites associated with the given exit. This assumes that, for each exit, total demand is shared evenly between each charging location. The result is the year-by-year average daily count of electric trucks recharging at each of the 43 sites across NIPSCO's main transportation corridors.

Daily arrivals at each site were then distributed over a 24-hour period using the 24-hour arrival profile from the Institute of Transportation Engineers Trip Gen data tool for Truck Stops.[41] For annual aggregation, traffic is assumed to be 25% lower on weekends and federal holidays.

To translate total vehicle charges to energy, NIPSCO identified the class-specific SoC of each vehicle visiting a given fueling/charging point based on its relative positioning to its logical highway endpoints. The corridor endpoints identified in this forecast are included in Table 3-19.

40 The 10% assumption was based on historical data.

41 https://www.ite.org/technical-resources/topics/trip-and-parking-generation/other-resources/

Table 3-19: Defined Highway Segments (US DOT)

Interstate	NW endpoint	SE endpoint
I-65	Chicago	Indianapolis
I-69	Lansing	Fort Wayne
I-90	Chicago	Cleveland
I-94	Chicago	Detroit
US-30	Chicago	Fort Wayne

SoC values were assigned for each route based on one of four categories:

1. Category 1: Route originates at one highway endpoint and terminates at another endpoint. Assume 30% of the battery is charged en route.
2. Category 2: Route originates at a highway endpoint and terminates elsewhere. Assume 60% of the battery is charged en route.
3. Category 3: Route doesn't originate at a listed highway endpoint but terminates at a local endpoint. Assume 30% of the battery is charged en route.
4. Category 4: Route originates and terminates in places other than the highway endpoints. Assume 70% of the battery is charged en route.

Differentiating how SoC values were assigned across length of freight routes also allowed NIPSCO to avoid double counting with at-home charging and local vehicle traffic. This was achieved by assuming that charging needs of vehicles on the shortest routes or those based within the NIPSCO service territory would be lower than demand from vehicles on long-haul routes. For example, a trip that starts in Chicago and ends in Detroit will only charge 30% of its total battery while a vehicle that is charging en route for a trip that might extend across the entire country is assumed to charge 70%.[42]

NIPSCO used the following baseline assumptions for MDVs and HDVs charging along NIPSCO's primary corridors. Medium-duty vehicles, such as single-unit trucks, were assumed to have a 300 kWh battery; Heavy-Duty vehicles were assumed to have a battery size of 600 kWh.

3.4.6.4 Energy and Power Calculation

To return hourly energy consumption, NIPSCO applied the assigned SoC ratios and battery attributes to the 24-hour charging distribution curve for each vehicle class across each segment of the highway. Finally, the total energy consumption for each corridor segment was split between each identified truck charging site to get the hourly energy consumption per site.

[42] Informed by the Freight Analysis Framework Version 5 Data Tabulation Tool." Oak Ridge National Laboratory

Each of the vehicle categories was assigned to a charger rating to calculate power requirements:

- MDV: 150kW
- HDV: 450kW

To calculate peak power demand, NIPSCO employed an hourly energy consumption approach, where hourly energy consumption was matched to the minimum number of required chargers based on vehicle class. This assumes that any required charge below the thresholds above will create a demand of the next highest charger threshold. For example, if two arriving trucks require 50 kWh each for a total of 100 kWh, there will be power demand of 150 kW (one 150 kW charger). This approach may require vehicles to wait for an available charger.

To account for changes in seasonal demand, NIPSCO applied seasonal shaping factors based on the temperature impacts defined in the EVI-Pro-Lite tool. This matches the seasonal variation seen in the native LDV and MDV vehicles and reflects the higher charging demand seen during extreme temperatures, particularly very cold temperatures.

3.4.6.5 Results of Northern Indiana Corridor EV Forecast

In total, power demand over an average 24-hour period across all charging sites is projected to peak at 67 MW. Given the current state of the market, NIPSCO assumes that site operators will be conservative in their investment in charging infrastructure, and vehicle operators will be willing to wait for access to chargers. Thus, the net demand has been modeled to be slightly lower. The average weekday corridor charging shape in 2030 across scenarios is shown in Figure 3-25. Average daily corridor energy consumption for each year of the study period is shown in Figure 3-26.

Figure 3-25: Average Weekday Corridor Charging Shape (2030)

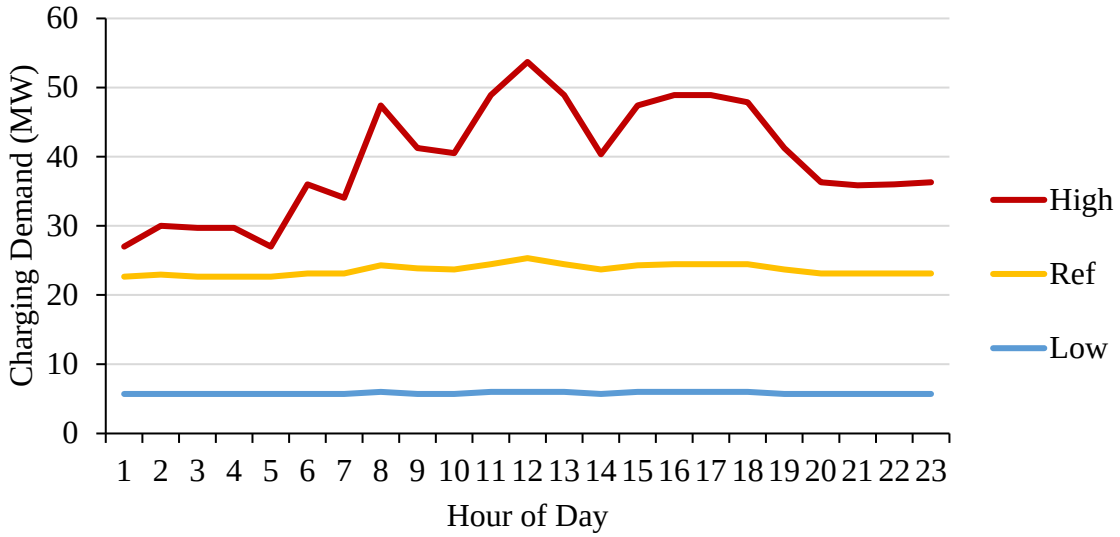
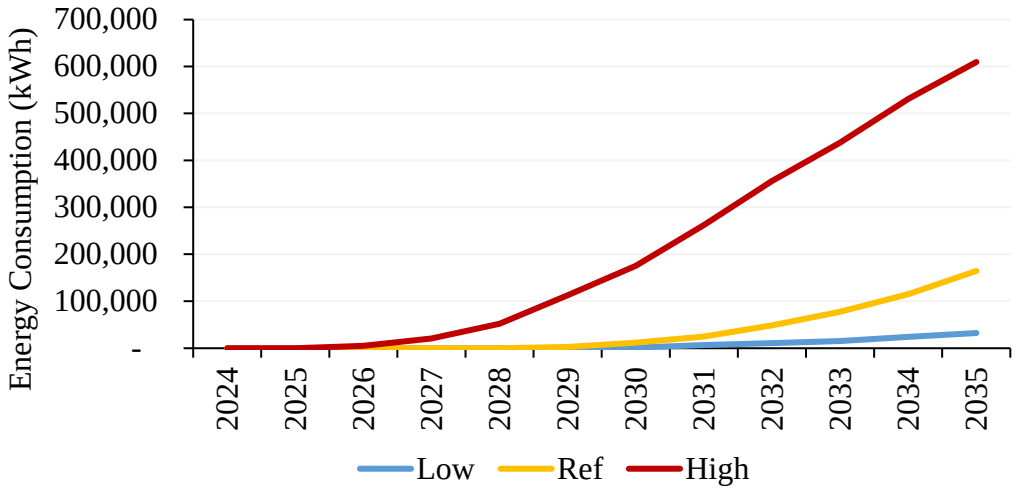


Figure 3-26: Average Daily Corridor Energy Consumption (kWh)



The results of the EV corridor charging forecast indicate that trucks charging en route within NIPSCO's service territory will make up 9.4% of total EV charging sales by 2035 in the reference case. This contribution increases to 21.1% in the high scenario and decreases to 5.1% in the low case, representing the varied states of heavy-duty freight adoption and related charging infrastructure. Total annual sales from corridor-based EV charging across the reference case, low case, and high case are shown in Figure 3-27, Figure 3-28, and Figure 3-29, respectively.

Figure 3-27: Annual Corridor EV Energy Demand – Reference Case (GWh)

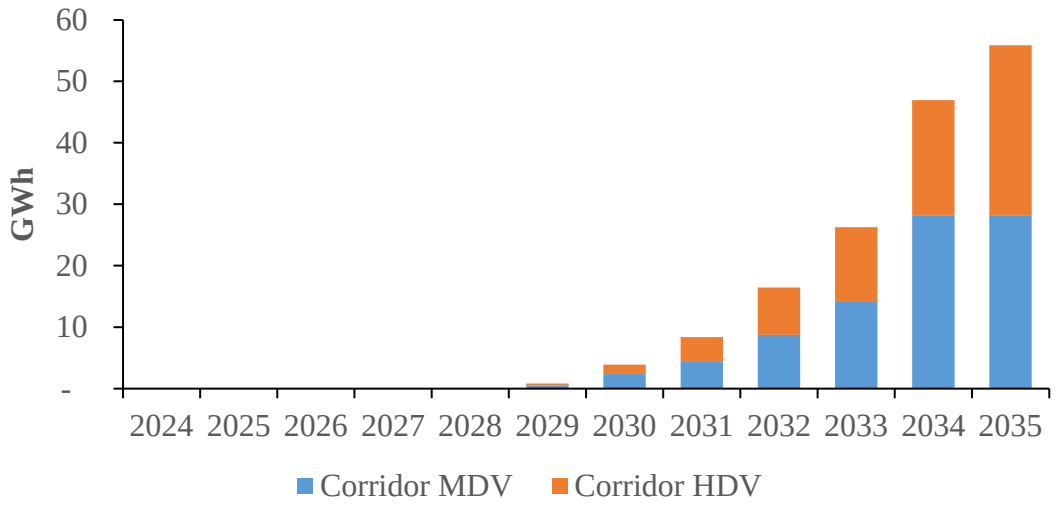


Figure 3-28: Annual Corridor EV Energy Demand – Low Case (GWh)

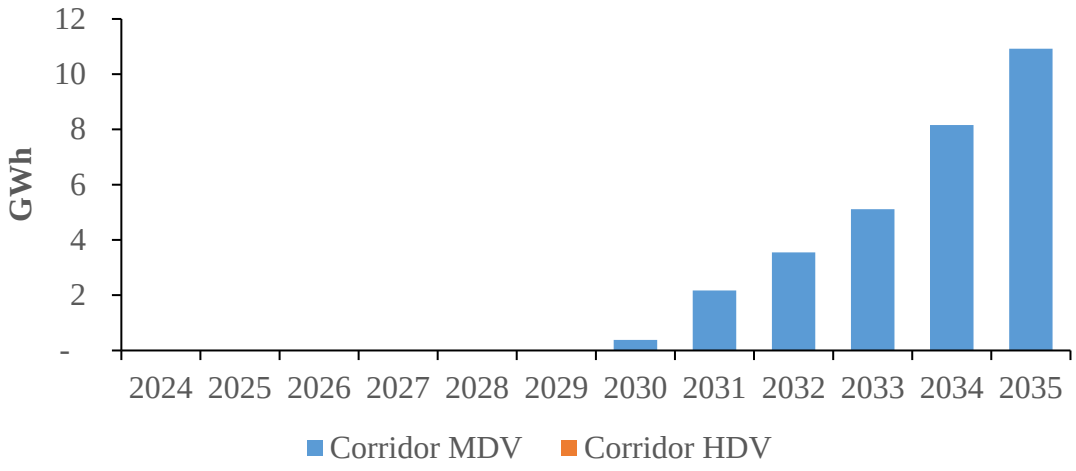
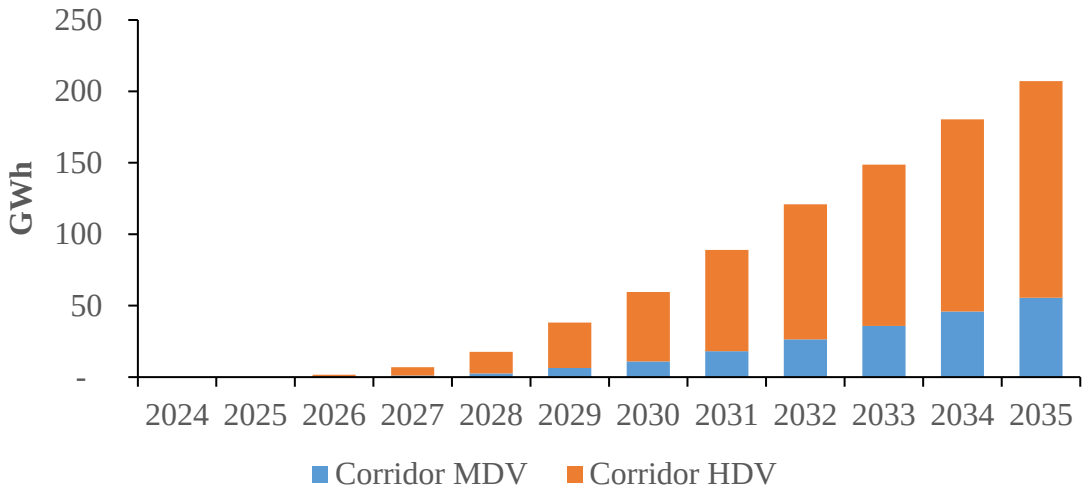


Figure 3-29: Annual Corridor EV Energy Demand – High Case (GWh)



3.4.7 Electric Vehicle Forecast Results

3.4.7.1 Annual EV Energy and Peak Load Forecasts

Annual electric vehicle energy demand for the reference, low, and high cases are shown in Figure 3-30, Figure 3-31, and Figure 3-32, respectively. As seen in these figures, light-duty vehicles are the major driver of EV load across all scenarios. For example, they comprise nearly 85% of total EV demand in 2045 in the reference case. After LDVs, native MDVs are the next greatest driver of increasing energy demand. Lastly, charging from medium- to heavy-duty-vehicles along Northern Indiana's six primary shipping corridors contribute to increasing growth, particularly in the high scenario. Although the low case assumes minimal adoption of heavy-duty electric vehicles, charging for HDVs contributes over a fifth of the total EV charging energy demand by 2035 under the high case.

Figure 3-30: Annual EV Energy Demand – Reference Case (GWh)

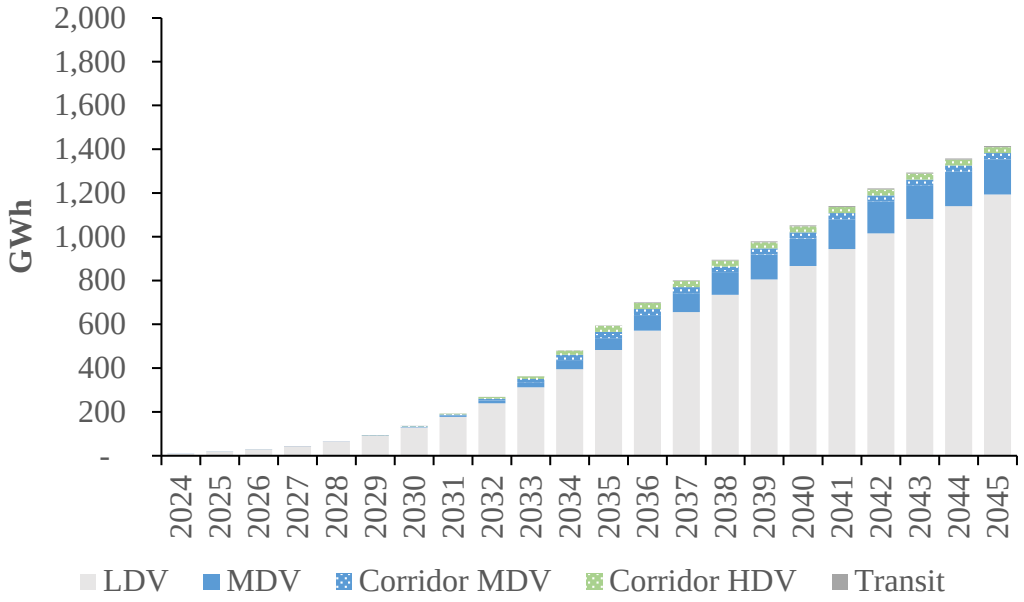


Figure 3-31: Annual EV Energy Demand – Low Case (GWh)

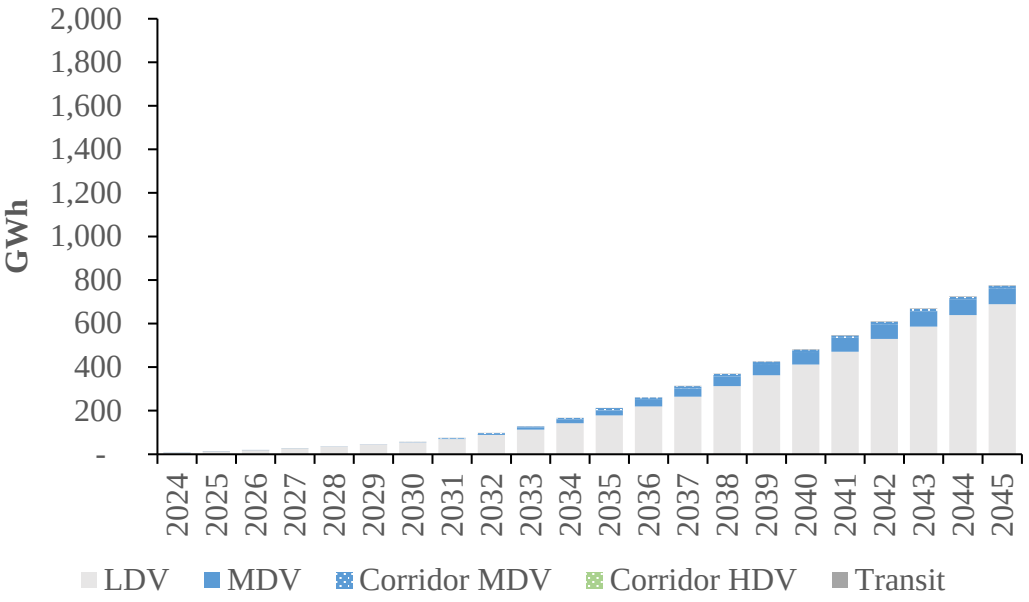
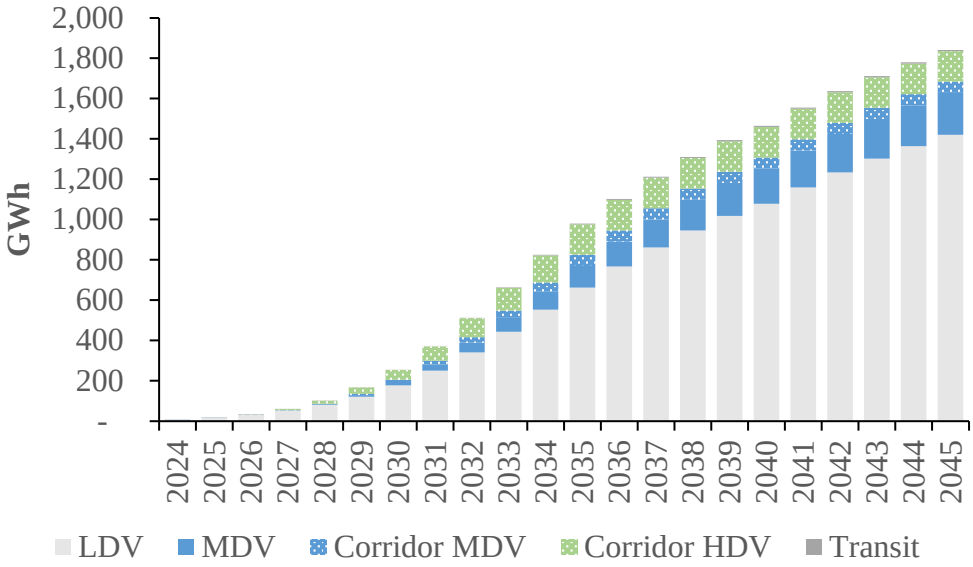


Figure 3-32: Annual EV Energy Demand – High Case (GWh)



3.5 Customer-Owned DERs

Customer-owned DERs are expected to grow throughout NIPSCO's territory, and this may materially impact NIPSCO's net sales and peak demand requirements. To estimate a range of impacts for DER penetration in the 2024 IRP, NIPSCO deployed CRA's agent-based PenDER model - customized and calibrated to NIPSCO's existing database of DER customers - to predict the customer adoption of DERs. NIPSCO's DER study focused exclusively on solar PV resource since this technology type (with or without storage) is expected to be the most widespread DER resource type at the residential and commercial levels.[43] In addition, the study focused on two main customer groups likely to adopt DER: residential and commercial.

3.5.1 Existing Solar Distributed Energy Resources

In its territory, NIPSCO has established DER programs for eligible electric customers (residential and commercial) with small-scale solar, wind, and hydro installations:

- Feed-in Tariff (FiT): Although now closed for intermediate solar systems (10kW – 200 kW), customers registered in this program, can sell power back to NIPSCO at a predetermined rate.[44]
- Net Metering (NM): Under this program, customers can generate their own electricity to offset their monthly usage, and any extra generation receives energy

[43] Note that distributed storage additions to pair with solar DERs were included as part of the Demand Side Management study.

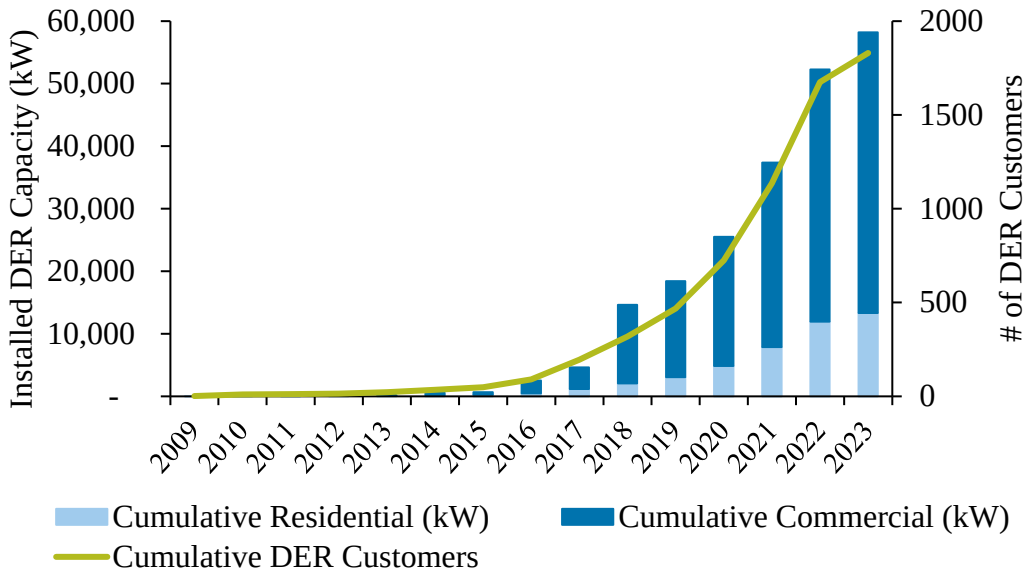
[44] Please find more detailed information on the Feed-in Tariff program here.

credits that can be applied to future usage.[45] However, the program ended on October 1, 2021 for commercial customers and on June 30, 2022 for residential customers.

- EDG Tariff: Currently, the only DER program receiving new applications. Under this tariff, customers with excess generation will receive utility bill credits that can be applied to reduce their future bill by 125% of the wholesale price power for all excess DER generation.[46]

Based on customer adoption data, collected as of September 2023, 1,830 electric customers have installed small-scale solar systems throughout NIPSCO's service territory. Solar DER adoption has increased 32% annually, reaching a total deployment of 58 MW, with residential customers totaling 13 MW and commercial customers totaling 45 MW. Figure 3-33 illustrates the historical cumulative number of customers with DERs and the installed DER solar capacity by customer class, under the NM and EDG programs in the NIPSCO territory. Table 3-20 and Table 3-21 present the existing solar DER Adoption by County within the NIPSCO Territory for residential and commercial customers. Among residential customers, 80% of the solar DER adoption is concentrated in four counties: Elkhart, Lake, LaPorte, and Porter. On the commercial side, 78% is concentrated in five counties: Elkhart, Lake, LaPorte, LaGrange, and Kosciusko.

Figure 3-33: Cumulative Total DER Customers and Solar DER Adoption by Customer Class under NM and EDG Programs



Approximately 16 customers have adopted solar plus battery systems, totaling 98 kW, with an average two-hour battery duration. Most storage systems have been installed by residential customers, with an average solar to storage ratio of 1.5:1.

[45] Please find more detailed information on the Net Metering program here.

[46] Please find more detailed information on the Excess Distributed Generation Tariff here.

Table 3-20: Existing Residential (Res.) Solar DER Adoption, by County, within the NIPSCO Territory

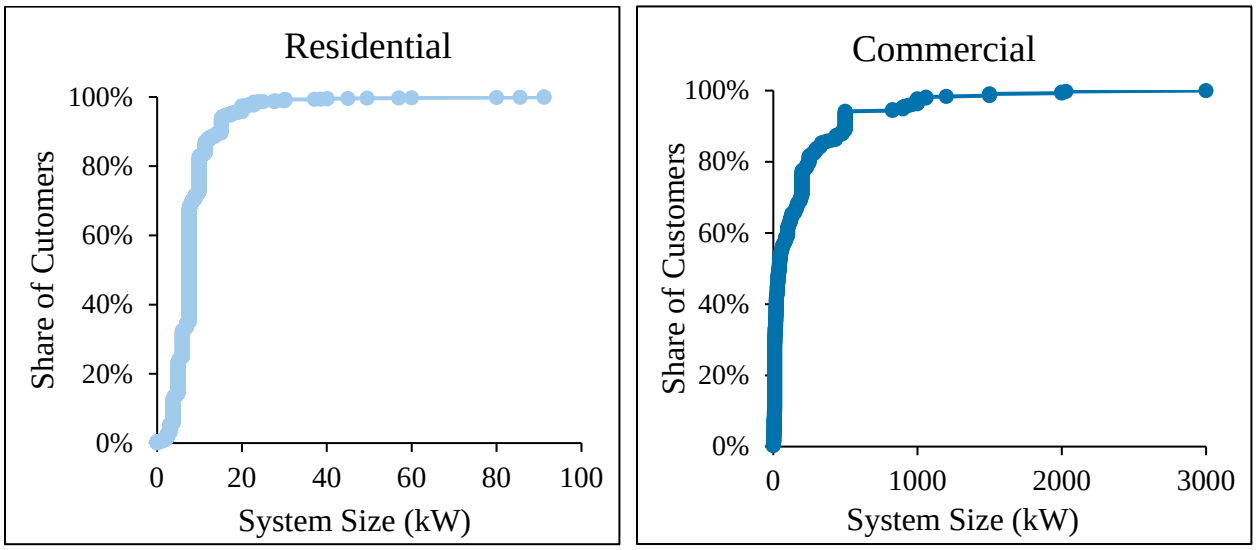
NIPSCO Counties	Total Res. Customers	Res. Solar DER Customers	% Res. Customers with Solar DER	Total Res. Solar DER (kW)
Benton	3,592	7	0.2%	60
Carroll	6,477	13	0.2%	113
DeKalb	3,035	23	0.8%	272
Elkhart	44,330	477	1.1%	4,830
Fulton	4,487	24	0.5%	248
Jasper	11,026	28	0.3%	277
Kosciusko	19,847	61	0.3%	587
LaGrange	6,841	31	0.5%	292
Lake	239,312	422	0.2%	3,181
LaPorte	54,911	192	0.3%	1,544
Marshall	7,026	15	0.2%	112
Newton	3,760	17	0.5%	141
Noble	1,126	4	0.4%	30
Porter	68,129	161	0.2%	1,264
Pulaski	2,368	8	0.3%	90
St. Joseph	171	3	1.8%	23
Starke	287	1	0.3%	8
Steuben	9,662	21	0.2%	153
White	532	4	0.8%	60
Total	486,919	1,512	0.3%	13,284

Table 3-21: Existing Commercial (Com.) Solar DER Adoption, by County, within the NIPSCO Territory

NIPSCO Counties	Total Com. Customers	Com. Solar DER Customers	% Com. Customers with Solar DER	Total Com. Solar DER (kW)
Benton	636	3	0.5%	230
Carroll	1,027	4	0.4%	536
DeKalb	415	14	3.4%	1,322
Elkhart	5,691	115	2.0%	19,222
Fulton	627	3	0.5%	360
Jasper	1,475	10	0.7%	1,500
Kosciusko	2,889	15	0.5%	3,219
LaGrange	1,337	20	1.5%	4,042
Lake	21,673	24	0.1%	2,810
LaPorte	6,097	51	0.8%	5,913
Marshall	1,060	10	0.9%	1,327
Newton	593	3	0.5%	311
Noble	178	4	2.2%	236
Porter	6,629	15	0.2%	1,682
Pulaski	328	1	0.3%	8
St. Joseph	31	0	0.0%	-
Starke	52	0	0.0%	-
Steuben	1,691	9	0.5%	1,942
White	136	7	5.1%	210
Total	52,565	308	0.6%	44,869

The average system size for residential customers is 8.6 kW, with a median of 7.6 kW, and approximately 80% of installed systems are below 10 kW. For commercial customers, the average system size is 178 kW, with a median of 40 kW, and around 60% of installed systems are below 100 kW, indicating higher system size diversity among commercial customers. For commercial customers, in recent years, following the EDG rate program implementation, system sizes have averaged 125 kW (median of 35 kW). Figure 3-34 illustrates the system size distribution of the historical adoption of solar DER systems for residential (left) and commercial (right) customers.

Figure 3-34: Solar DER System Size Distribution under Residential (left) and Commercial (right) Customers



3.5.2 Customer-Owned Distributed Energy Resource Projections

3.5.2.1 PenDER Model Description

PenDER is an agent-based model developed by CRA that simulates the adoption decisions and interactions via social networks of thousands of autonomous agents to provide granular forecasting of DER adoption. Techno-economic variables and demographic characteristics of the simulated agents contribute to an individual agent's probability to adopt DER based on an economic review of retail rate expectations, wholesale rates projections, the costs of installing DER, and potential financial incentives.

- The techno-economic variables deployed in the PenDER modeling for NIPSCO's 2024 IRP include:
  - The capital cost of a solar PV system, inclusive of expected ITC benefits
  - Solar capacity factor and solar system lifetime expectations
  - Average solar DER system size
  - Retail rates and wholesale rates projections (for EDG)
  - Assumptions for customer discount rate and for inflation rate
- The socio-economic and demographic data required to characterize customer groups (agents) in PenDER consist of:
  - Existing population with DER adoption
  - Household income
  - Total housing units and housing characteristics (detached, attached, apartments, etc.)
  - Business type

- Energy usage

The combination of the techno-economic variables and agent income levels are then used to develop a calculation of payback period and household budget to assess the probability of DER adoption through a calibrated logit probability function.

While economics play an important role in the decision to install DER, the personal propensity and communal influences to adopt new technology also play a role, as described through the Bass diffusion model of technology forecasting.[47] Therefore, the simulated agents are randomly assigned a "Bass innovation index," representing their personal propensity on a scale of early adopters to laggards of a new technology. Relationships between agents are modeled through "social networks," with an average size of 13 agents belonging to one network. As more agents in one's network adopt DER, the more likely a given agent will also adopt.

Ultimately, PenDER was set up for each county with the NIPSCO territory, where an agent's decision to adopt DER is influenced by the combination of techno-economic factors (through payback period and household budget) as well as personal and communal influences (through personal preferences and network effects).

3.5.3 Key Input Assumptions

NIPSCO developed techno-economic assumptions for each of its five market scenarios[48] to develop a range of potential future customer-owned solar DER penetration levels. The techno-economic input assumptions for PenDER used in NIPSCO's 2024 IRP under each scenario are summarized in Table 3-22 and described in more detail in the remainder of this section.

Table 3-22: Solar DER Techno-economic Assumptions by Scenario

	Reference Case	Slow Transition	Domestic Resiliency	Aggressive Environmental Regulation	Accelerated Innovation
	Ref	ST	DR	AER	AI
Capital Cost	Med	High	High	Med	Low
ITC	Current Policy	Early IRA phase out	Current Policy	Current Policy	Current Policy
Wholesale Rates Growth	Base	Low	High	High	Base
DER Program	EDG continues through 2045	EDG continues through 2045	EDG continues through 2045	EDG transitions back to NM Program	EDG continues through 2045

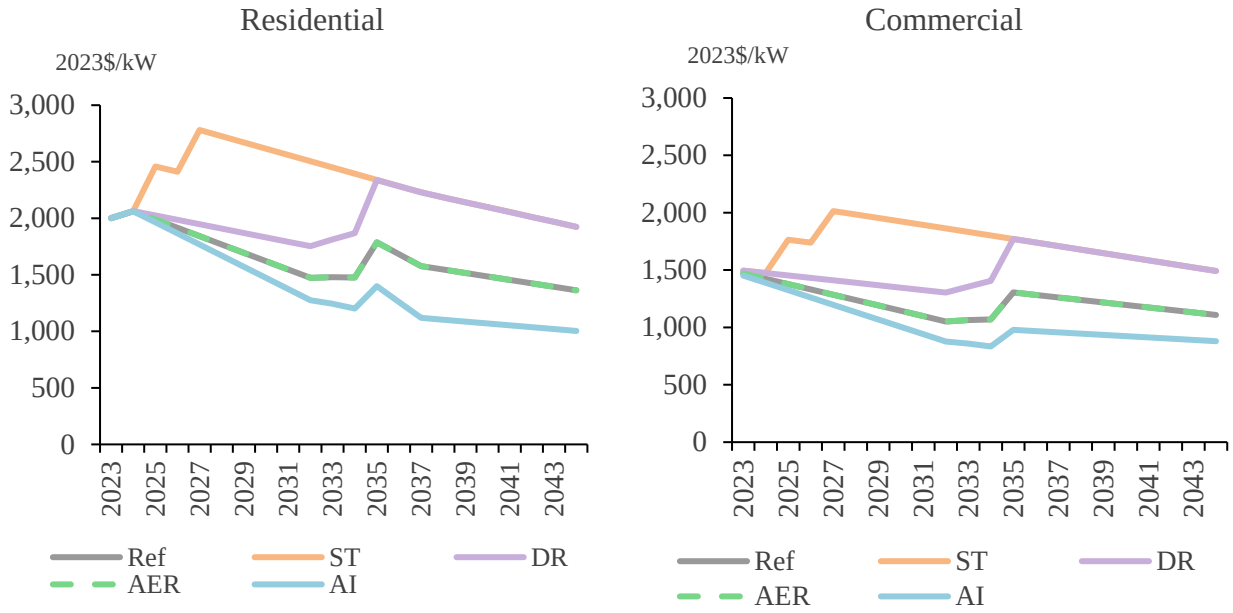
Capital Cost and Tax Credit Inputs: Assumptions regarding capital cost projections, capacity factor, and lifetime for solar PV were taken from NREL's 2023 Annual Technology Baseline for

[47] See Bass, F. (1969). "A New Product Growth for Model Consumer Durables." *Management Science*. 15 (5): 215-227

[48] Note that NIPSCO's five scenarios are described in more detail in Section 8.

the Advanced (Low cost), Moderate (Medium cost), and Conservative (High cost) cases for both residential and commercial solar PV technologies – Class 5 Rooftop PV.[49] Assumptions regarding the federal ITC were consistent with the provisions under the IRA and with those defined across NIPSCO's five core planning scenarios, where solar ITC benefits are available until 2035 in all but one scenario.[50] Figure 3-35 shows the solar DER system cost trajectories for residential (left) and commercial (right) customers by scenario, inclusive of the impact of the federal ITC.

Figure 3-35: Solar DER System Cost Trajectories by Case, including ITC, for Residential (left) and Commercial (right) Customers



Wholesale Rate Real Growth Rate: Wholesale rate growth is uncertain and dependent on NIPSCO's generation plan, commodity prices, the wider MISO market, regulatory policy, transmission and distribution system cost drivers, and several other factors. NIPSCO developed a range of wholesale rate real growth rates with broad alignment to NIPSCO's five core planning scenarios. The Reference and AI scenarios assume a base annual growth rate of 0.7%, the ST scenario has a lower rate growth of 0.2%, the DR scenario has a higher annual growth rate of 1.2%, and the AER has the highest wholesale growth rate of 3.6%.

Net Metering / Excess Distributed Generation: NIPSCO's Net Metering and Excess Distributed Generation programs are governed by Indiana Code Ch. 8-1-40 and the Commission's Rules and General Administrative Orders. The DG Statute establishes the methodology under which NIPSCO procures electricity supplied by customers with qualifying distributed generation resources and offsets the cost of the electricity supplied to such customers. The DG Statute requires that an electricity supplier's net metering tariff remain available until the earlier of the following: "(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of

[49] NREL (National Renewable Energy Laboratory), 2023. 2023 Annual Technology Baseline. Golden, CO.
[50] Note that under the Slower Transition scenario, the ITC is assumed to phase out by 2026.

net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier [or] (2) July 1, 2022." As of January 1, 2021, the aggregate amount of net metering facility nameplate capacity under NIPSCO's net metering tariff exceeded 1.5% of its most recent summer peak load (the statutory threshold), and NIPSCO filed Cause No. 45505 to gain Commission approval for an Excess Distributed Generation Rider. Since the NIPSCO Excess Distributed Generation Rider was approved, PenDER simulated most future scenarios under the EDG program. In one scenario–AER–a transition back to a rate design similar to the prior NM rate is assumed. These policy scenarios were designed to assess a broad range of potential DER penetration outcomes.

Solar System Characteristics: Information regarding the average size of DER solar installations currently on NIPSCO's system was used to define future system sizes. Historical system size averages are approximately 8 kW for residential customers and 125 kW for commercial customers. NIPSCO estimated CF for the DER systems based on NREL's 2023 Annual Technology Baseline for both residential and commercial solar PV technologies – Class 5 Rooftop PV – and assumed a 25-year life for solar projects.

Financial Inputs: Assumptions regarding the financing of PV systems, namely the WACC, were developed based on the rationale that the WACC for residential and commercial customers would be at a premium to the financing costs for utility-scale solar. NIPSCO also has assumed that small customers (i.e., residential) have higher financing costs than larger-scale customers with better access to capital.

Table 3-23: Residential and Commercial Project Parameter Assumptions

	Residential	Commercial
Average PV Size	8 kW	125 kW
Solar CF	15.5%	15.5%
Solar Lifetime	25 years	25 years
Inflation	2.1%	2.1%
Real After-Tax WACC	7.00%	6.00%

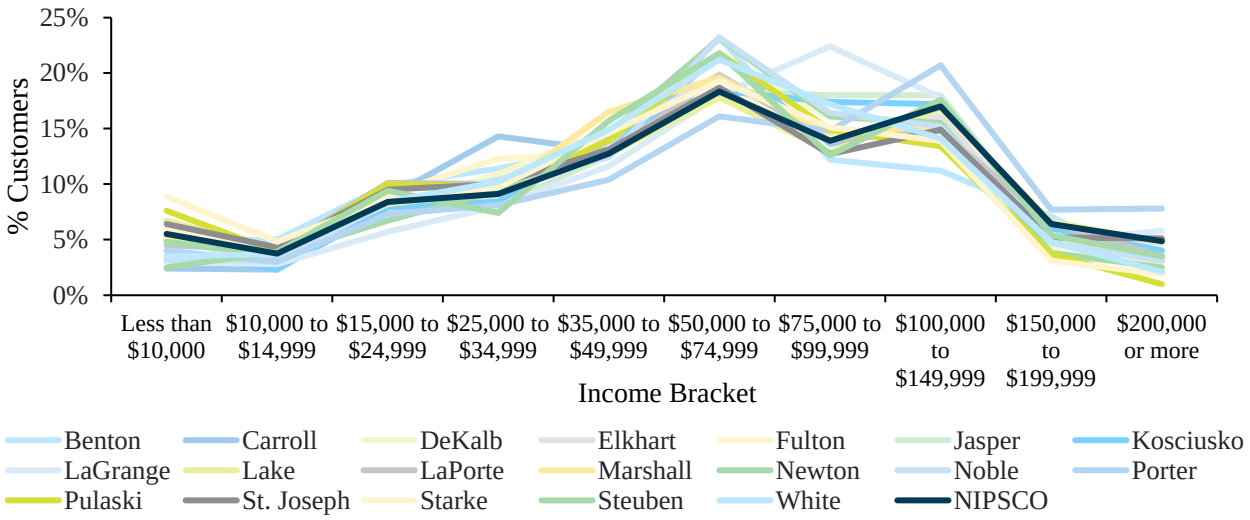
Household Income: Household income distributions by county within the NIPSCO territory were determined from the ACS. The ACS is a nationwide survey that collects and produces information on demographic, housing, economic, and social characteristics of the nation's population every year.[51] Household income is defined as the "pretax cash income of the householder and all other people 15 years and older in the household, whether or not they are related to the householder."[52] For each county, agents in the PenDER model were assigned a household income level to preserve consistency with the distribution of income levels, by county, in NIPSCO's service territory from

[51] For more detailed information referred to ACS's website.

[52] Guzman, G. (September 2020). "Household Income: 2019". *American Community Survey*. https://www.census.gov/content/dam/Census/library/publications/2020/acs/acsbr20-03.pdf

the ACS's five-year *Selected Economic Characteristics* Table.[53] Figure 3-36 shows the county-level household income distribution assumptions used in the model. On average, 42% of residential customers, across counties, report a medium income above $75,000/year (U.S. median household income, based on 2022 ACS data), with a distribution range between 32% and 51%.

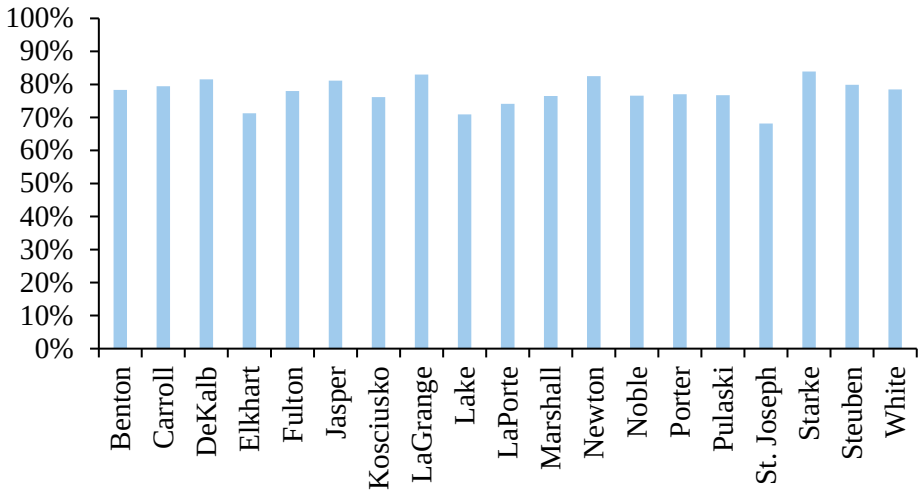
Figure 3-36: Household Income Distribution by County



Housing Units: The single-detached, owner-occupied housing units, by county, were also assessed from the ACS to determine the total population of agents with the potential to adopt solar DER. Figure 3-37 shows the estimated maximum percentage of customers with the potential to install solar DER systems.

[53] Retrieved from the ACS's 2022 Data Release.

Figure 3-37: Estimated Percentage Customers with Solar DER Potential



Solar DER-related Grants: On April 22, 2024, the city of Gary, located in Lake County, Indiana, was awarded a monetary grant from the U.S. Environmental Protection Agency for low-income solar projects, under the *Solar for All* program.[54] In PenDER, it is assumed that, approximately 3,000 low-income residential customers will install solar DER systems through this grant.

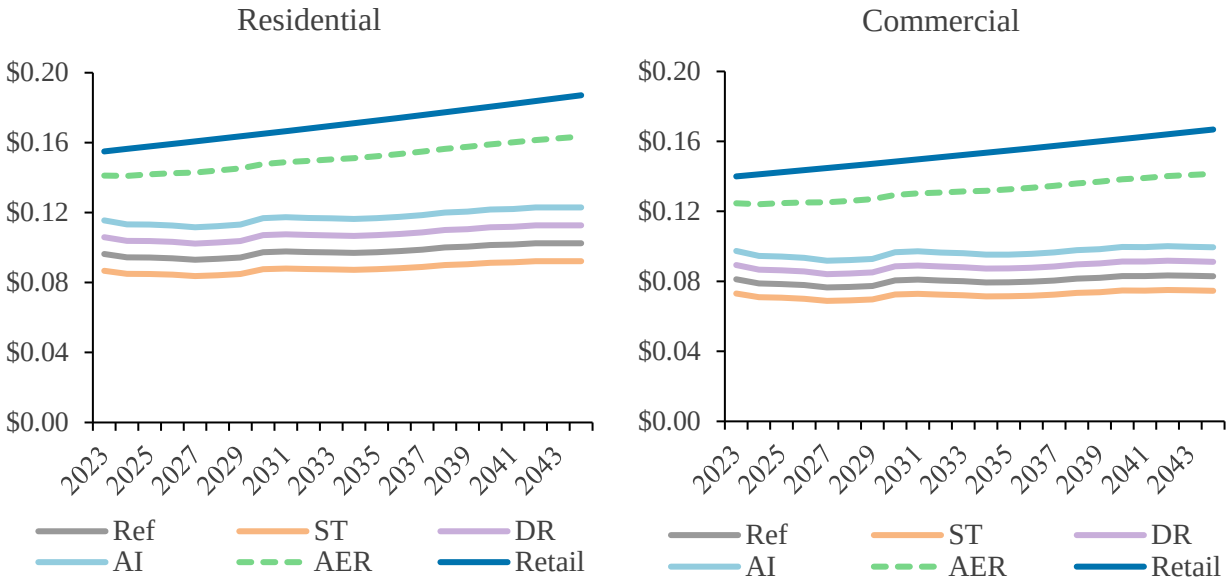
Bass Innovation Index Parameters: By using NIPSCO's customer adoption numbers from 2012 through 2023 from the Net Metering program, PenDER's bass innovation index parameters were calibrated to match historical adoption decisions (using historic retail rates and solar PV capital costs).

Based on the input assumptions described above, internally, for each simulation, PenDER calculates the following parameters assigned to each agent:

- **System Value**: For each agent, the expected cash inflow, resulting from installing a solar DER system, is estimated as annual production (based on expected solar capacity factor), in kWh, multiplied by the inferred retail rate savings as well as the monetization of excess generation at the wholesale rate in $/kWh. Figure 3-38 shows the estimated value streams for residential (left) and commercial agents (right) by scenario. The ST scenario exhibits lower value than the Reference scenario due to lower wholesale rates, while other scenarios assume higher retail and wholesale rates, which increase value for the DER. The AER scenario assumes excess generation can be valued at the retail rate. Note that for commercial customers, a greater percentage of value is assumed to be derived from the retail rate savings than for residential customers even though retail rates are lower.

[54] For more information, refer to EPA's Solar For All Program.

Figure 3-38: Solar DER Value Streams, in 2023$/kWh, for Residential (Left) and Commercial (Right) Customers, by Scenario



- **Customer Budget**: A budget is assigned to each agent via probability distribution, informed by the 2022 ACS five-year census estimates. The customer budget parameter is omitted from the commercial customer forecast, as commercial agents are assumed to act economically and can utilize loans.

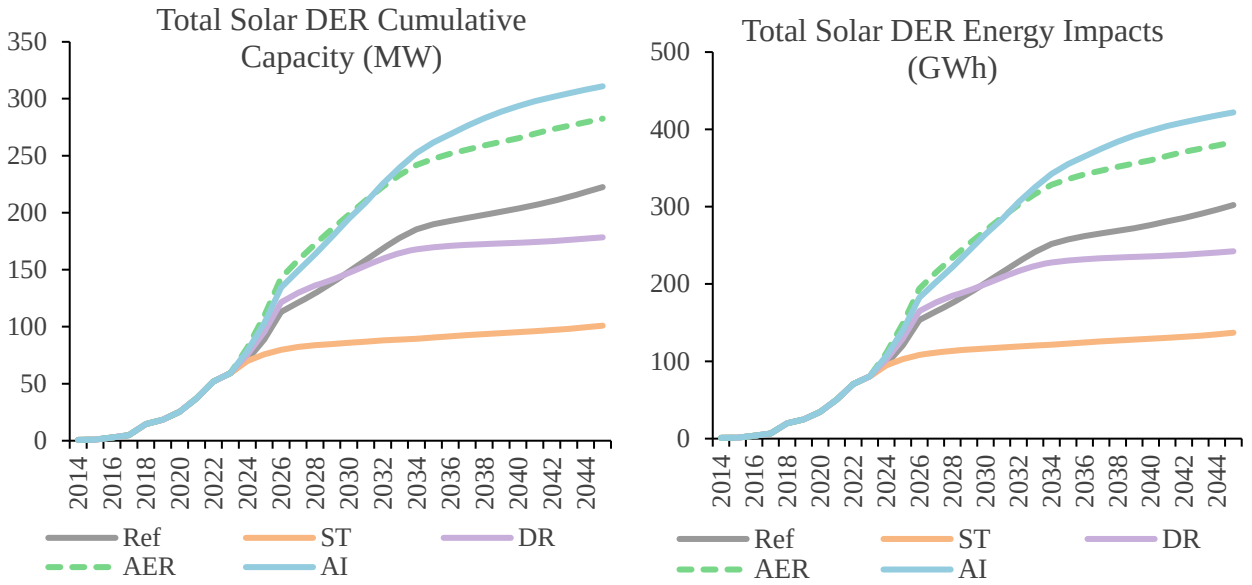
- **Payback Period**: Based on the upfront PV system capital cost, the cash flow from renewable energy incentives (i.e., EDG rates), discount rate, and solar PV lifetime, the payback period is determined by the number of years of discounted annual revenues that are required to cover the upfront PV system cost.

3.5.3.1 DER Forecast Results

Using all the input assumptions outlined above, NIPSCO deployed the PenDER model to estimate a range of DER penetration levels across the five major planning scenarios. Projections for total cumulative customer-owned solar DER installations and associated cumulative energy impacts, by scenario, are summarized in Figure 3-39,[55] while the disaggregated results for the residential customer class are shown in Figure 3-40, and the results for the commercial class are presented in Figure 3-41. In aggregate, a range of approximately 100 MW to 310 MW of DER capacity is projected across scenarios by 2045.

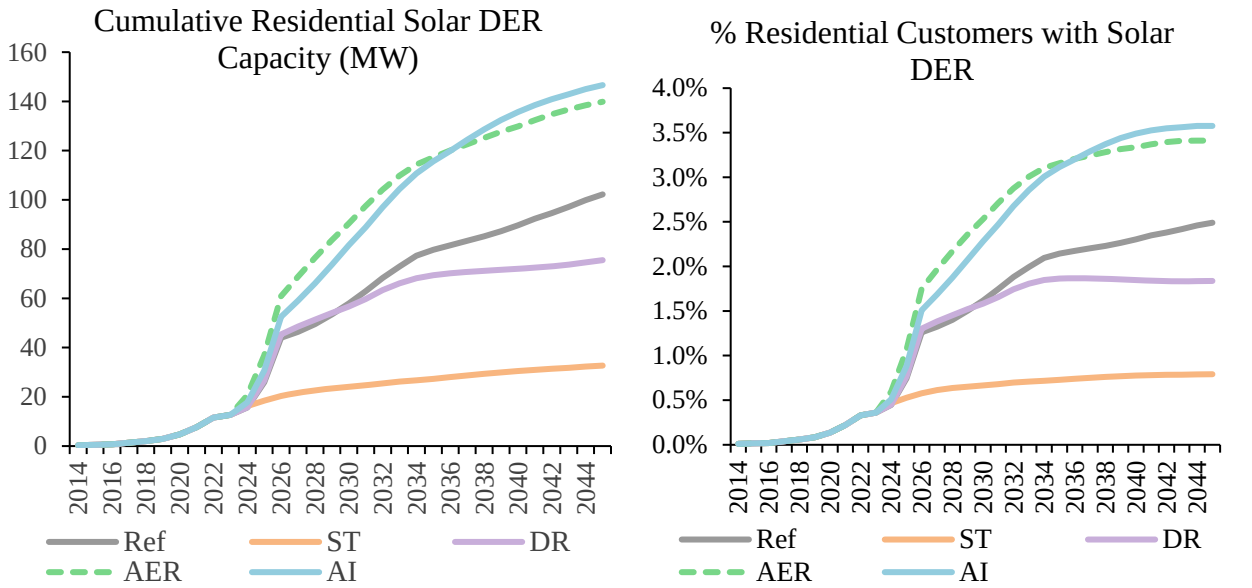
[55] Note that this graphic displays energy projections at the customer meter. For purposes of inclusion in the IRP load forecast modeling, NIPSCO grossed up the energy impact by 5% to incorporate line losses.

Figure 3-39: Projected Cumulative Customer-Owned DER Installations (MW) and Associated Energy (GWh) Impact, by Scenario



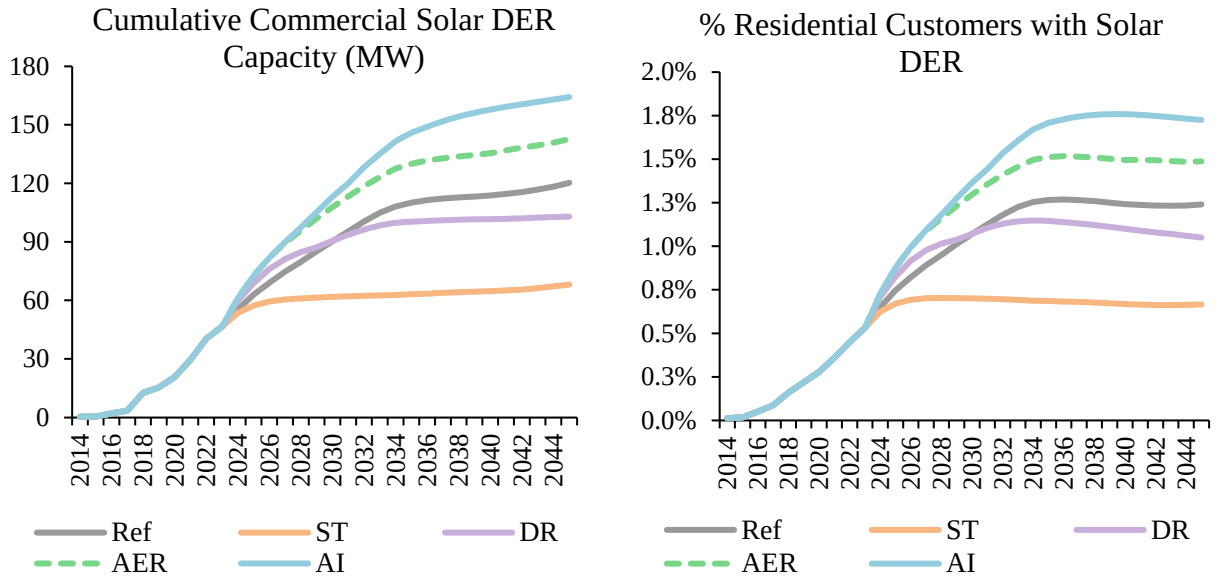
Across scenarios, it is estimated that between 0.8% and 3.6% of residential customers will install solar DER systems by 2045. There is a notable uptick in expected penetration in the early years, driven in part by the implementation of the Solar for All program among residential customers in selected counties. Over the long term, growth is impacted by scenario variables associated with system costs, system value, and social network effects. The solar DER penetration forecast for residential customers is summarized in Figure 3-40.

Figure 3-40: Projected Solar DER Penetration for the Residential Class, by Scenario



Across scenarios, it is estimated that between 0.7% and 1.7% of commercial customers will install solar DER systems by 2045. Despite an overall lower percentage of commercial customer adoption, commercial solar DER installations have far larger system sizes, pushing total installed capacity higher (depending on the scenario) than residential values. The solar DER penetration forecast for commercial customers is shown in Figure 3-41.

Figure 3-41: Projected Solar DER Penetration for the Commercial Class, by Scenario



3.6 Large Economic Development Loads

Following NIPSCO's first IRP Stakeholder Advisory meeting held on April 23, 2024, there was a significant increase in data center announcements in Indiana, including one public announcement in the NIPSCO service territory. In response to this development and its potential impact on future energy demand in the service territory, NIPSCO updated its Reference Case load forecast and developed an additional large load sensitivity load forecast.

NIPSCO and Indiana are both attractive to data center developers due to many favorable factors, such as a low risk for natural disasters; robust transmission network and reliability; available land at relatively reasonable prices; telecommunication connectivity and fiber optic cable; access to water; and proximity to customers, major metropolitan areas, and construction labor. Additionally, Indiana is a pro-business state with strong incentives for data center development. Indiana provides a sales and use tax exemption on purchases of qualifying data center equipment and energy to operators of a qualified data center for a period not to exceed 25

years for data center investments of less than $750 million.[56] Local governments have also provided local tax abatements and incentives on qualified enterprise information technology equipment to owners of a data center who invest at least $25 million in real and personal property in the facility, furthering incentives and likelihood of future data center load in Indiana and NIPSCO's service territory.[57]

At the time of the second NIPSCO IRP Stakeholder Advisory meeting held on June 24, 2024, there were six active data center projects in NIPSCO's service territory that had begun or taken steps to begin development activities and in were in discussions with NIPSCO. These six projects are initially expected to increase NIPSCO's anticipated annual total peak demand up to approximately 8,600 MW by 2035. As such, these new loads were an essential component in the 2024 IRP core analytical framework.

NIPSCO has an obligation to serve current and expected load from existing customers in its service territory and to reasonably plan for potential load growth. NIPSCO has developed perspectives on how much new large load may enter the system over time. NIPSCO estimated the potential energy demand from these projects in consultation with NIPSCO's Economic Development team and other internal subject matter experts. Projections were based on prospective and actual near-term customer prospects, as well as potential long-term industry-wide growth trends. These internal and industry projections were incorporated into the 2024 Load Forecast through the development of load projections for new projects that are expected to come online beginning in 2028 through 2035 ("Large Economic Development projects"). Figure 3-42 displays the anticipated incremental load attributable to Large Economic Development projects in the NIPSCO service territory. The Reference Case load forecast includes 600 MW of new demand attributable to Large Economic Development projects beginning in 2028. To account for further data center and large industrial load growth over the IRP horizon, new demand attributable to Large Economic Development projects rises to approximately 2,600 MW by 2035.

[56] If the investment exceeds $750M, the Indiana Economic Development Corporation may award an exemption for up to 50 years. This program is established by Indiana Code § 6-2.5-15.

[57] St. Joseph County and the City of LaPorte have both offered incentives to recently announced data center developments. *See* https://nwindianabusiness.com/community/economic-development/microsoft-chooses-la-porte-as-first-indiana-data-center-location/65133/ and https://www.wvpe.org/wvpe-news/2024-05-31/st-joseph-county-officials-eye-tax-breaks-for-massive-amazon-data-center

Figure 3-42: Projected New Large Load Additions

	2028	2030	2035
IRP Peak Load – Original Reference Case	2,300 MW	2,300 MW	2,500 MW
+New Load Added to All IRP Scenarios	*600 MW*	*1,600 MW*	*2,600 MW*
IRP Peak Load – New Reference Case	**2,900 MW**	**3,900 MW**	**5,100 MW**
+Emerging Load Sensitivity	*2,600 MW*	*4,500 MW*	*6,000 MW*
Total IRP Peak Load with Emerging Load Sensitivity	**5,500 MW**	**8,400 MW**	**11,100 MW**

The six aforementioned Large Economic Development projects are part of a potential wave of increased economic activity in the Northwest Indiana region, largely resulting from potential increased demand for data centers and related cloud storage/computing services. NIPSCO included the Emerging Load scenario to account for increased data center demand beyond the Reference Case. The Emerging Load projects 3,200 MW in new demand by 2028 and rising to 8,600 MW of new demand by 2035.

The anticipated growth in demand related to Large Economic Development project load is a new and rapidly changing phenomena in the NIPSCO service territory. NIPSCO's analysis in the 2024 IRP was intended to provide initial guidance with the facts available at the time the core analysis was conducted. NIPSCO, however, will continue to monitor and evaluate the development of Large Economic Development projects in the coming years. Further, NIPSCO will continue to refine its analysis of potential Large Economic Development load additions in future IRPs and other long-term portfolio planning analyses.

3.7 All-in Load Summary

Figure 3-43 depicts total net energy for load across customer classes in the Reference Case inclusive of adjustments from EVs, DERs, and new Economic Development loads, as well as losses associated with transmission and distribution.[58] Figure 3-43 below shows the contributions of all customer classes and load types to summer and winter peak load across all years in the reference case.

The largest diver of load growth in the Reference case is new loads associated with large Economic Development projects in the region. In the Reference case, these projects are projected to contribute 2,600 MW of peak load above the base forecast, making up nearly 50% of total summer peak demand and growing at a CAGR of 17.4% between 2027 and 2034.

[58] Note that a loss factor of 4.62% was assumed to arrive at the "net energy for load" forecast that must be served by NIPSCO's generation resources. Transmission system losses are 1.62% and distribution system losses are 3%.

Figure 3-43: Total Net Energy for Load by Customer Class, with Adjustments (MW)

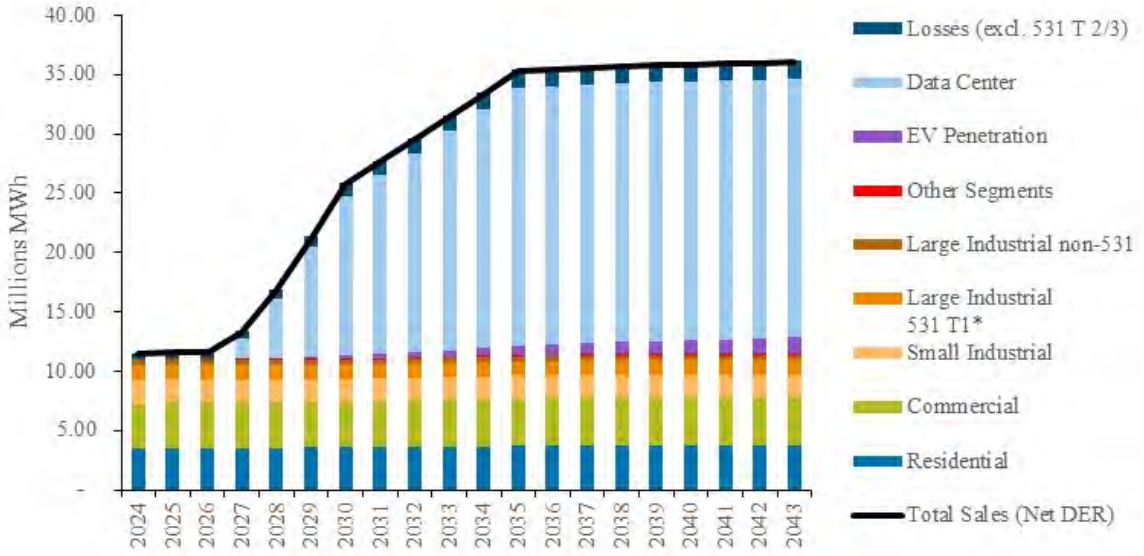
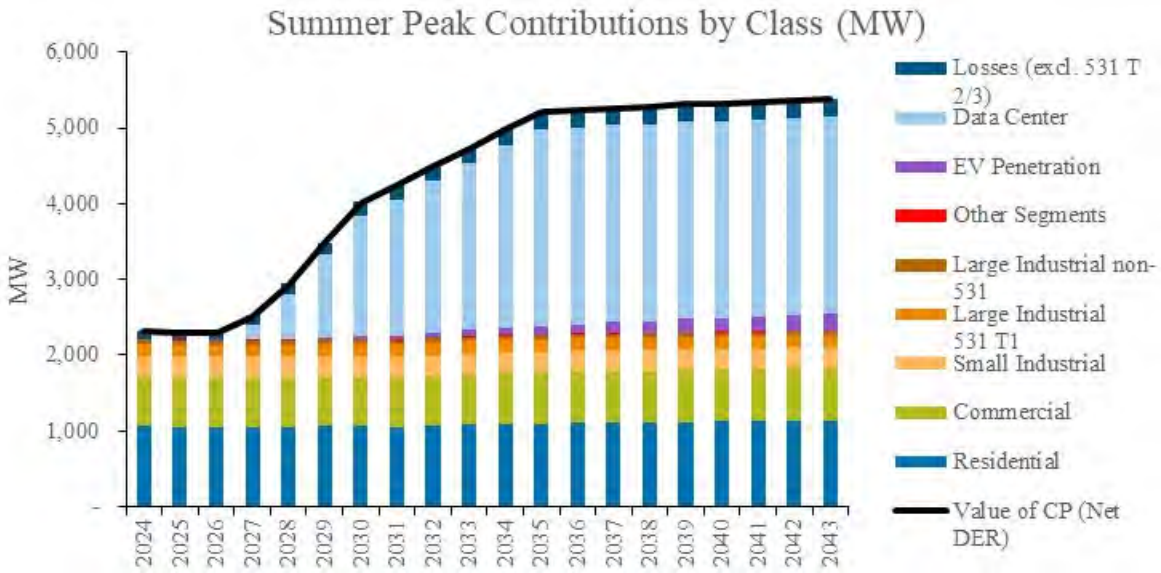
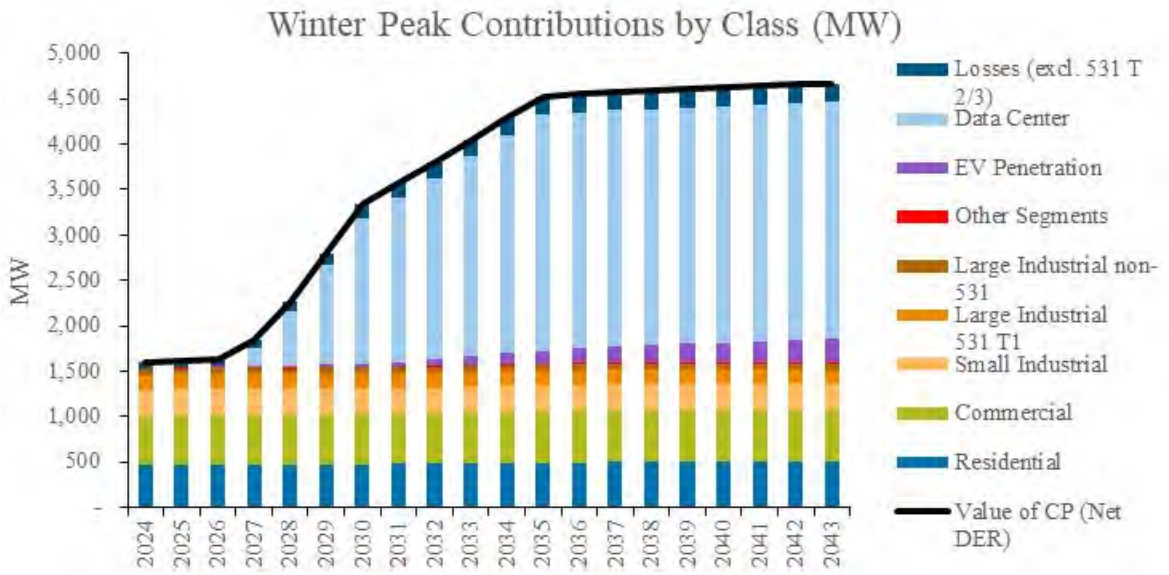


Figure 3-44: Summer and Winter Peak Contributions by Customer Class, with Adjustments (MW)





3.8 Scenario Analysis

NIPSCO combined the econometric modeling analysis with the EV, DER, and large economic development load analyses across all five planning scenarios to develop a range of future load growth outcomes, as outlined in Table 3-24. Each of these scenarios provides an internally consistent view of a possible future state of the world. The remainder of this section outlines the key drivers of scenario uncertainty and provides a summary of the forecasts.

Table 3-24: Scenario Drivers Summary

	Scenario Name	Description	Economic Growth (C&R, I Count)	EV Penetration	DER Penetration	Electrification (MISO Futures Report)	Large Econ. Development Load
	**Reference Case**	Reference Point	**Base** Moody's Baseline forecast	**Base** Rate of Adoption	**Base** Expected Rate of Adoption	**Limited (Future 1)**	
	**Slower Transition**	Environmental policy incentives reduce; economic slowdown in region	Low Moody's Low forecast ↓	Low Rate of Adoption ↓	Lowest High capital costs, low tax credits, low wholesale prices ↓	**Limited (Future 1)**	*Separate sensitivity with significant additional economic development load potential, across all scenarios*
	**Domestic Resiliency**	Influx of new economic development load	**Base** Moody's Baseline forecast	**Base** Rate of Adoption	Lower High capital costs ↓	**Limited (Future 1)**	
	**Aggressive Environmental Regulation**	Aggressive decarbonization policy, moderate electrification	**Base** Moody's Baseline forecast	High Rate of Adoption ↑	High Net metering policy change ↑	High **(Future 2)** ↑	
	**Accelerated Innovation**	Faster energy transition, high electrification with additional econ. dev. load	**Base** Moody's High forecast	High Rate of Adoption ↑	High Low capital costs, larger installation sizes ↑	Highest **(Future 3)** ↑	

3.8.1 Economic Variables

NIPSCO relied on Moody's macroeconomic data for forecasts of the econometric variables described in Section 1.3.1. NIPSCO used the Moody's Baseline forecast for the Reference Case as of October 2023 (also used for Domestic Resiliency, Aggressive Environmental Regulation, and Accelerated Innovation scenarios) and deployed the Alternative Scenario 3 - Downside - 90th Percentile for the low case (mapped to the Slower Transition scenario).

3.8.2 Electric Vehicles

NIPSCO developed a range of EV penetration scenarios and resulting charging demand, as described in Section 1.4. These low, base, and high scenarios are mapped to the scenarios, as summarized in Table 3-24.

3.8.3 Distributed Energy Resources

NIPSCO developed a range of DER penetration scenarios with resulting impacts on the load forecast, as described in Section 1.5 and mapped to the scenarios as summarized in Table 3-24.

3.8.4 Other Electrification

For the AER and AI scenarios, NIPSCO incorporated additional electrification impacts according to the electrification study developed by AEG for MISO's MTEP 2021 process.[59] This study incorporated potential electrification of residential and commercial/industrial heating, hot water, appliances, and commercial/industrial processes. NIPSCO adopted the projections for MISO LRZ 6 (scaled to account for only NIPSCO's portion of LRZ 6[60]) and added increasing energy demand due to electrification, as summarized in Figure 3-45 (AI Scenario) and Figure 3-46 (AER Scenario). The seasonal and annual peak demands are also impacted. As many of the electrification impacts have larger demand impacts in the winter than summer, this peak demand growth occurs asymmetrically in the winter.

[59] https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

[60] Electrification was assumed to occur symmetrically across the LRZ6 footprint. As such, NIPSCO was assumed to account for 12% of the electrification, in line with its historical portion of LRZ6 sales.

Figure 3-45: Electrification Impact on NIPSCO Energy Sales (AI Scenario)

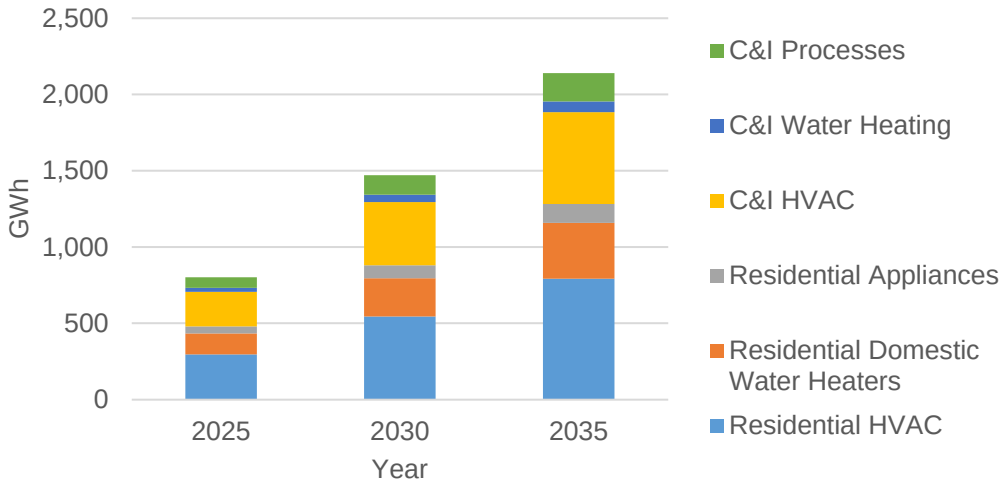
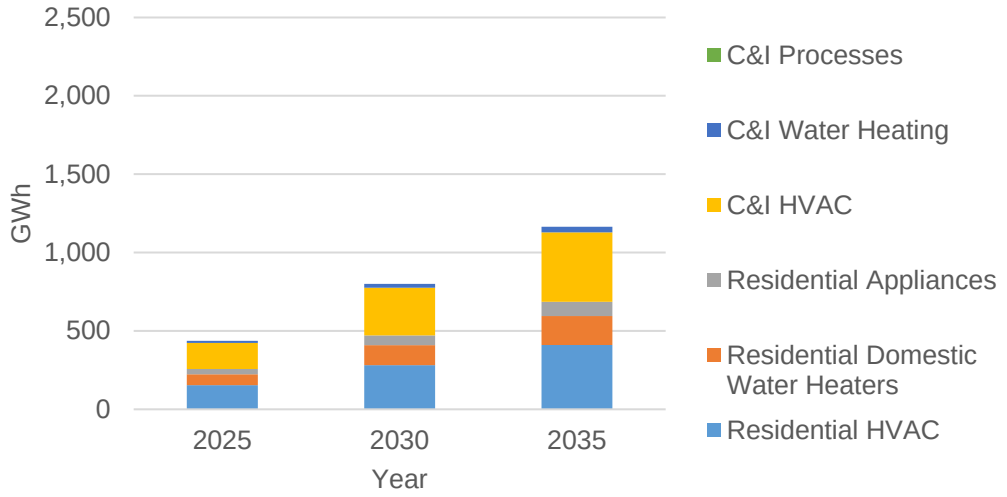


Figure 3-46: Electrification Impact on NIPSCO Energy Sales (AER Scenario)



3.8.5 Industrial Load Risk

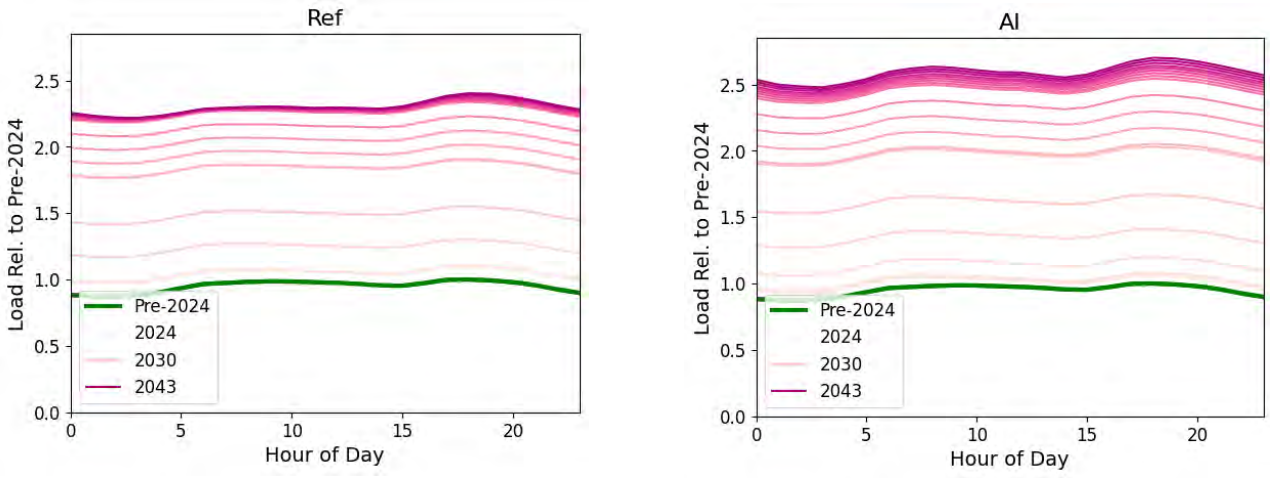
For the Slower Transition scenario, NIPSCO assumed that total industrial sales continue to decline at the pre-COVID rate (-0.12% CAGR). This scenario also incorporated the potential for additional industrial load migration, since NIPSCO recognizes that Tier 1 commitments may decline over time, particularly after the Rate 831/531 Modification Agreement approved in Cause No. 45772. Although no firm declarations of commitment reductions have been made by any Rate 531 customer, and it is not certain that all seven current Rate 531 customers would elect to reduce their demand to the tariff minimum, NIPSCO incorporated the migration of 100 MW of load from Rate 531 Tier 1 to Rate 531 Tier 2 by 2030 in the Slower Transition scenario. By migrating to

Tier 2, this load would no longer be served by NIPSCO but would instead be procured by the customer(s) through NIPSCO.

3.8.6 Conversion from Sales to Peak

The base sales forecast (without the addition of EVs, DERs, electrification, or large loads) was converted to a peak load forecast using the load factor approach described in Section 1.3.5. However, the addition of EVs, DERs, and other sources of electrification can have a substantial impact on the hourly load shape. Given a sufficient change in shape, the hour of the peak load will change. An example of this changing hourly load shape for the winter season is shown in Figure 3-47 for the Reference and AI cases. The darker shades of pink in this figure indicate future years that are further into the planning horizon. As seen in this figure, both scenarios will experience a flattening of the hourly shape due to the additional high load factor, data center load. However, in the AI case, further load growth would occur in the early morning and evening hours due to the increased electrification of heating.

Figure 3-47: Winter Hourly Shaping Impacts to Load (Base, Accelerated Innovation)



As electrification grows, a larger portion of demand will be shifted to hours before the sun rises or after the sun has set, due to the impact of EV charging, DER growth, and new electrification. This growth will also occur asymmetrically across seasons. With sufficient growth, the hour of the peak will change. As such, it is not appropriate to simply add the contribution of new sources of load growth in the historic peak hour. Rather, for each year in the forecast horizon, NIPSCO simulated the addition of the new sources of electrification to the historical load shape. Under this *future* looking load shape, the new hour of peak load for each season is found. If the hour of peak is changed, the econometric load (i.e., load forecast without electrification impacts) is scaled to capture the lower contribution to peak in this hour. This scaling factor is taken as the historic ratio of load between the future peak load hour and historic peak load hour. Then the expected contribution of DERs, EVs, other sources of electrification, and large loads is added,

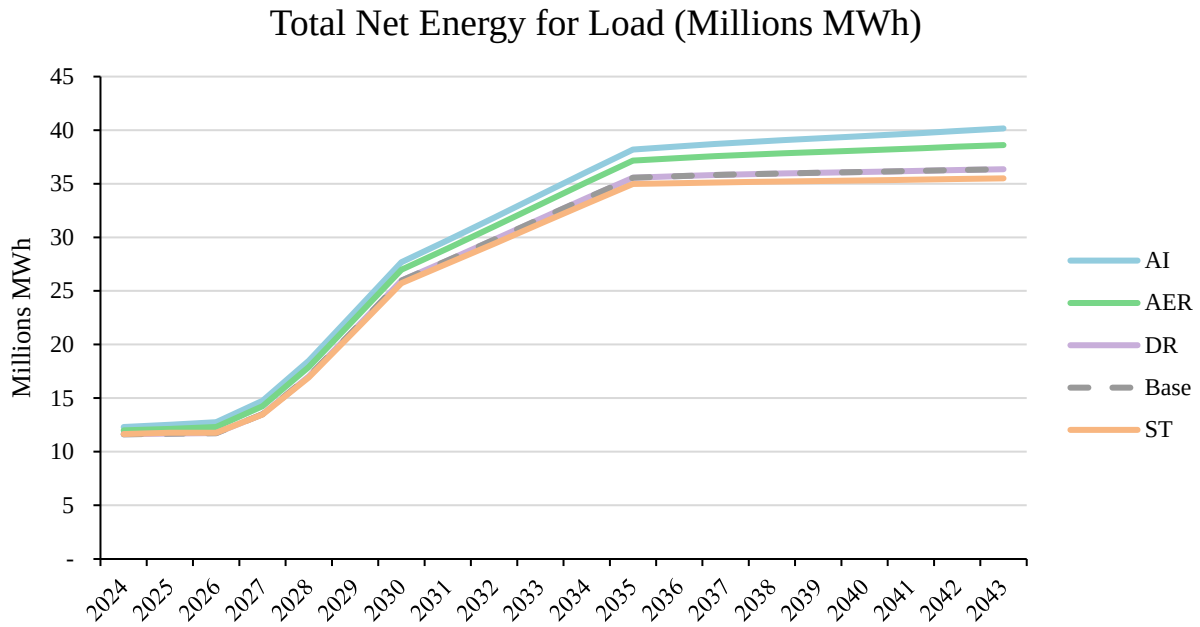
based on their expected performance in this new peak hour. For example, under current conditions, the peak may occur at 5 pm. However, with increasing DER and EV penetration, the new peak may be shifted back to 7 pm. To account for this change, the base load contribution to peak is scaled by current ratio of load demand at 7 pm versus 5 pm. Then the expected DER, EV, other electrification, and data center demand during this hour is added to synthesize the peak demand forecast.

3.8.7 Scenario Results

Figure 3-48 presents a summary of the total net energy for load forecast across the five planning scenarios and under the base outlook for large economic development loads.[61] In the short term, the varying techno-economic and policy assumptions driving differences in the econometric, EV, and DER forecasts are overshadowed by the magnitude of new large economic development loads (primarily data centers). Over the long run, other differences between scenarios begin to become more apparent. Higher demand in the AI and AER scenarios is driven primarily by increased charging demand from EVs in addition to increased assumptions around the electrification of traditional natural gas services, like space heating and cooking.

The Reference Case and DR scenarios forecast net sales to grow at a CAGR of 5.6%, while increased expectations around EV and electrification push up growth in the AER and AI scenarios to 5.9% and 6.1%, respectively.

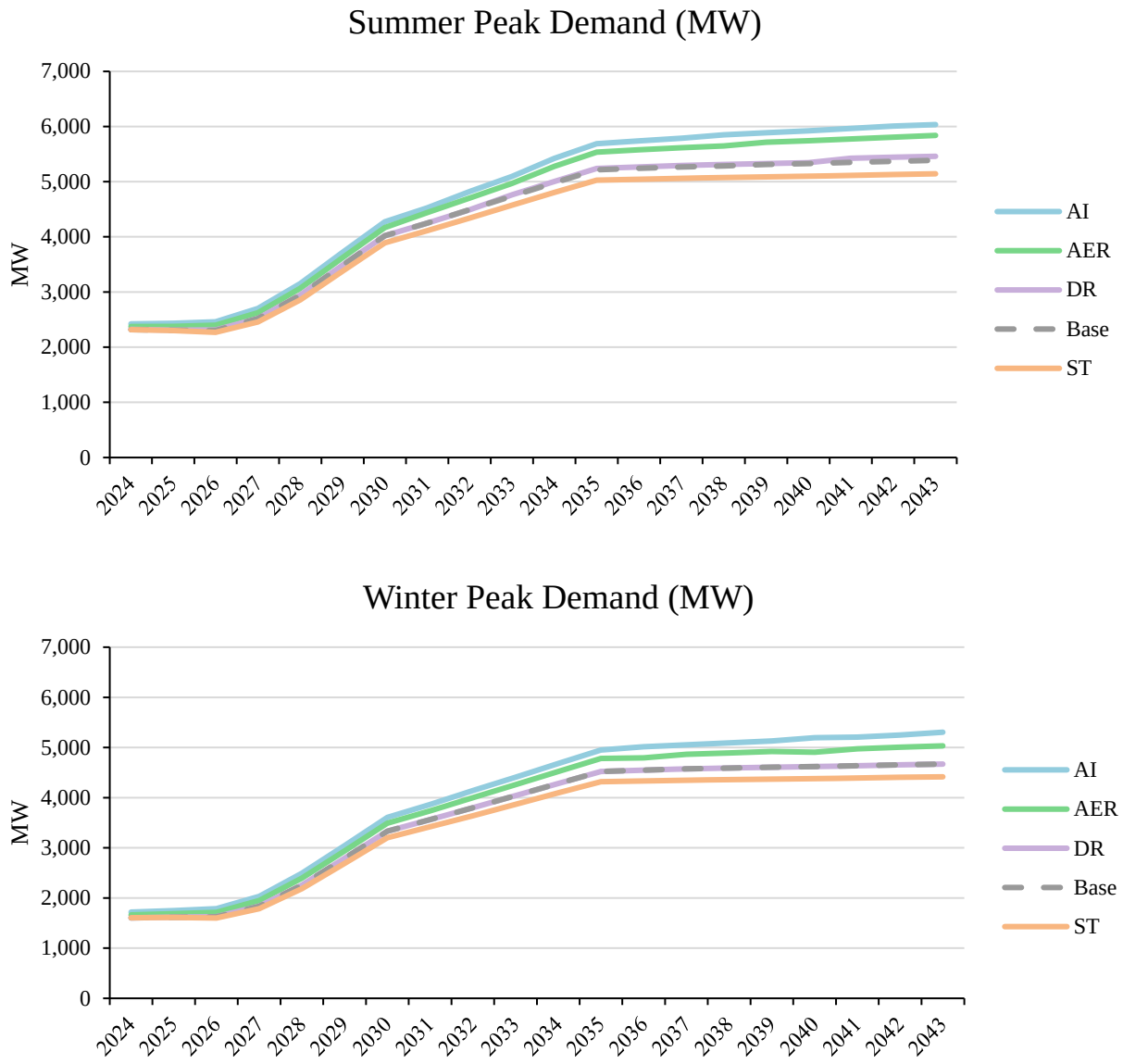
Figure 3-48: Total Net Energy for Load Forecast across Scenarios



[61] Note that the high data center load sensitivity described in Section 3.6 is not displayed in detail in these summaries. However, the additional load would be additive to all five scenarios.

Figure 3-49 depicts year-on-year demand in megawatts at the peak hour of each season across the five planning scenarios and under the base outlook for large economic development loads. In NIPSCO's 2024 load forecast, peak load is highest in the summer across the study period, indicating that the NIPSCO system is expected to be summer peaking across all scenarios. Compared to the trends in total net energy sales, the Reference (Base) and Domestic Resiliency cases diverge slightly as the hour in which demand is greatest shifts to later in the day. Additionally, the peak forecast provides a closer view at how the differences in electrification and EV assumptions drive variation across the scenario forecasts. The inclusion of 2,600 MW of Economic Development load in all scenarios by 2035 has overall caused load to be less dependent on variations in seasonal consumption and temperature.

Figure 3-49: Seasonal Peak Demand for Load Forecast across Scenarios



3.9 Detailed Forecast Results

The remainder of this section provides detailed annual sales and peak demand forecasts by customer class for the Reference Case and by category across all five scenarios.

Table 3-25: Customer Count Forecast by Major Customer Segment – Reference Case

Year	Residential	Commercial	Total Industrial
2024	426,564	58,798	2,180
2025	428,996	59,195	2,172
2026	431,867	59,673	2,174
2027	434,991	60,192	2,172
2028	438,219	60,728	2,165
2029	441,443	61,262	2,158
2030	444,644	61,790	2,150
2031	447,894	62,325	2,142
2032	451,275	62,880	2,136
2033	454,850	63,467	2,129
2034	458,602	64,081	2,122
2035	462,544	64,726	2,117
2036	466,657	65,397	2,113
2037	470,911	66,089	2,109
2038	475,345	66,809	2,105
2039	479,941	67,556	2,101
2040	484,694	68,327	2,097
2041	489,629	69,129	2,093
2042	494,752	69,960	2,089
2043	500,037	70,818	2,086
2024-2043 CAGR	**0.84%**	**0.98%**	**-0.23%**

Table 3-26: Electric Sales Forecast (Inclusive of Historical Energy Efficiency Programs Only and Prior to Other Adjustments) – Reference Case

Year	Residential	Commercial	Total Industrial	Other*	Total MWh (Before Adjustments)
2024	3,503,477	3,718,422	3,787,387	92,169	11,101,455
2025	3,514,494	3,766,036	3,773,392	92,169	11,146,090
2026	3,529,627	3,780,604	3,777,602	92,169	11,180,002
2027	3,532,326	3,784,527	3,774,703	92,169	11,183,726
2028	3,532,272	3,786,944	3,764,110	92,169	11,175,495
2029	3,554,454	3,790,559	3,751,459	92,169	11,188,642
2030	3,566,676	3,789,167	3,739,494	92,169	11,187,507
2031	3,579,386	3,807,605	3,733,065	92,169	11,212,225
2032	3,596,102	3,855,349	3,733,262	92,169	11,276,882
2033	3,628,006	3,910,399	3,732,019	92,169	11,362,594
2034	3,660,477	3,946,354	3,729,248	92,169	11,428,248
2035	3,682,470	3,964,104	3,724,461	92,169	11,463,205
2036	3,697,202	3,981,757	3,725,865	92,169	11,496,993
2037	3,711,092	3,996,678	3,723,603	92,169	11,523,543
2038	3,719,750	3,989,543	3,716,539	92,169	11,518,001
2039	3,728,274	3,986,334	3,709,475	92,169	11,516,253
2040	3,736,196	3,985,407	3,702,411	92,169	11,516,183
2041	3,743,898	3,984,567	3,696,228	92,169	11,516,863
2042	3,751,306	3,985,531	3,689,899	92,169	11,518,905
2043	3,758,286	3,983,727	3,683,416	92,169	11,517,598
2024-2043 CAGR	**0.37%**	**0.36%**	**-0.15%**	**0.00%**	**0.19%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-27: Summer Peak Load Forecast (Inclusive of Historical Energy Efficiency Programs Only and Prior to Other Adjustments) – Reference Case

Year	Residential	Commercial	Small Industrial	Large Industrial non-531	Large Industrial 531 T1	Other*	Total MW	System Wide Peak (Before Adjustments)
2024	1,062	639	282	53	165	13	2,214	2,316
2025	1,049	641	281	53	164	13	2,201	2,303
2026	1,045	643	281	53	164	12	2,198	2,300
2027	1,047	642	281	53	164	13	2,200	2,311
2028	1,049	643	280	53	164	13	2,202	2,331
2029	1,062	646	279	53	163	13	2,216	2,369
2030	1,062	645	278	52	163	13	2,214	2,391
2031	1,057	648	278	52	162	12	2,210	2,397
2032	1,073	656	278	52	162	13	2,235	2,433
2033	1,083	665	278	52	162	13	2,253	2,462
2034	1,093	671	278	52	162	13	2,269	2,489
2035	1,099	675	277	52	162	13	2,278	2,508
2036	1,105	678	277	52	162	13	2,287	2,518
2037	1,111	681	277	52	162	13	2,296	2,528
2038	1,116	681	277	52	162	13	2,300	2,533
2039	1,120	682	276	52	161	13	2,304	2,539
2040	1,125	683	275	52	161	13	2,309	2,544
2041	1,130	684	275	52	161	13	2,314	2,550
2042	1,135	685	275	52	160	13	2,320	2,557
2043	1,140	686	274	52	160	13	2,325	2,563
2024-2043 CAGR	**0.35%**	**0.38%**	**-0.16%**	**-0.16%**	**-0.16%**	**0.00%**	**0.19%**	**0.60%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-28: Reference Case Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In (Grossed Up for Losses after Adjustments)
2024	11,101,455	8,387	(96,434)	-	11,516,979
2025	11,146,090	17,333	(120,638)	-	11,547,732
2026	11,180,002	27,643	(153,370)	-	11,559,747
2027	11,183,726	42,832	(164,430)	1,677,648	13,323,122
2028	11,175,495	63,623	(175,489)	5,032,944	16,835,018
2029	11,188,642	113,184	(188,200)	9,227,064	21,275,231
2030	11,187,507	213,388	(201,181)	13,421,184	25,753,200
2031	11,212,225	311,898	(214,812)	15,098,832	27,623,025
2032	11,276,882	419,046	(229,041)	16,776,480	29,543,037
2033	11,362,594	517,016	(241,396)	18,454,128	31,477,436
2034	11,428,248	618,866	(251,751)	20,131,776	33,397,005
2035	11,463,205	729,158	(257,711)	21,809,424	35,297,891
2036	11,496,993	834,090	(261,968)	21,809,424	35,438,565
2037	11,523,543	934,292	(265,534)	21,809,424	35,567,444
2038	11,518,001	1,027,523	(268,813)	21,809,424	35,655,765
2039	11,516,253	1,111,218	(272,216)	21,809,424	35,737,946
2040	11,516,183	1,184,344	(276,205)	21,809,424	35,810,214
2041	11,516,863	1,272,435	(280,931)	21,809,424	35,898,151
2042	11,518,905	1,352,836	(285,280)	21,809,424	35,979,862
2043	11,517,598	1,425,081	(290,439)	21,809,424	36,048,688
2024-2043 CAGR	**0.19%**	**31.03%**	**5.97%**	**17.39%**	**6.19%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-29: Reference Case Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In
2024	2,316	1	(6)	-	2,311	1,602	2	-	-	1,604
2025	2,303	3	(7)	-	2,298	1,610	4	-	-	1,614
2026	2,300	4	(1)	-	2,302	1,617	6	-	-	1,623
2027	2,311	7	(9)	200	2,509	1,625	10	-	200	1,834
2028	2,331	10	(9)	600	2,932	1,643	14	-	600	2,257
2029	2,369	17	(10)	1,100	3,476	1,669	24	-	1,100	2,792
2030	2,391	29	(11)	1,600	4,008	1,692	40	-	1,600	3,332
2031	2,397	40	(2)	1,800	4,236	1,704	57	-	1,800	3,561
2032	2,433	59	(4)	2,000	4,487	1,720	77	-	2,000	3,797
2033	2,462	73	(5)	2,200	4,731	1,744	97	-	2,200	4,040
2034	2,489	89	(5)	2,400	4,973	1,765	117	-	2,400	4,282
2035	2,508	106	(5)	2,600	5,210	1,781	140	-	2,600	4,520
2036	2,518	123	(5)	2,600	5,236	1,788	160	-	2,600	4,548
2037	2,528	138	(5)	2,600	5,261	1,793	180	-	2,600	4,573
2038	2,533	152	(5)	2,600	5,280	1,792	198	-	2,600	4,590
2039	2,539	173	-	2,600	5,312	1,792	214	-	2,600	4,606
2040	2,544	184	-	2,600	5,329	1,792	227	-	2,600	4,619
2041	2,550	199	-	2,600	5,349	1,792	245	-	2,600	4,637
2042	2,557	212	-	2,600	5,369	1,793	261	-	2,600	4,654
2043	2,563	225	-	2,600	5,387	1,793	276	-	2,600	4,669
2024-2043 CAGR	**0.53%**	**30.87%**	**-**	**17.39%**	**4.56%**	**0.60%**	**29.74%**	**-**	**0.09%**	**5.79%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-30: ST Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In (Grossed Up for Losses after Adjustments)
2024	11,143,111	8,387	(94,777)	-	11,560,367
2025	11,242,166	13,749	(102,858)	-	11,657,835
2026	11,241,562	18,962	(108,170)	-	11,650,771
2027	11,197,073	25,733	(111,569)	1,677,648	13,357,508
2028	11,143,548	33,837	(113,654)	5,032,944	16,812,458
2029	11,144,584	43,866	(115,083)	9,227,064	21,204,277
2030	11,142,715	63,262	(116,539)	13,421,184	25,605,488
2031	11,164,977	110,122	(117,936)	15,098,832	27,431,503
2032	11,227,051	135,674	(119,352)	16,776,480	29,276,753
2033	11,310,312	166,762	(120,480)	18,454,128	31,150,300
2034	11,373,514	203,619	(121,409)	20,131,776	33,009,104
2035	11,406,853	248,603	(122,782)	21,809,424	34,844,637
2036	11,439,970	296,605	(124,049)	21,809,424	34,927,973
2037	11,466,264	349,142	(125,494)	21,809,424	35,008,803
2038	11,460,667	405,039	(127,040)	21,809,424	35,059,765
2039	11,458,710	461,555	(128,305)	21,809,424	35,115,485
2040	11,458,571	516,724	(129,273)	21,809,424	35,172,022
2041	11,459,009	581,606	(130,393)	21,809,424	35,239,126
2042	11,461,035	644,550	(131,432)	21,809,424	35,305,884
2043	11,459,442	704,082	(133,088)	21,809,424	35,364,732
2024-2043 CAGR	**0.15%**	**26.26%**	**1.80%**	**17.39%**	**6.06%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-31: ST Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In
2024	2,315	1	(6)	-	2,310	1,604	2	-	-	1,606
2025	2,293	2	(1)	-	2,294	1,610	3	-	-	1,613
2026	2,268	2	(1)	-	2,269	1,596	4	-	-	1,600
2027	2,252	4	(7)	200	2,449	1,580	6	-	200	1,786
2028	2,250	5	(7)	600	2,848	1,576	8	-	600	2,184
2029	2,270	7	(7)	1,100	3,370	1,581	10	-	1,100	2,691
2030	2,279	8	(1)	1,600	3,886	1,586	13	-	1,600	3,200
2031	2,294	14	(1)	1,800	4,107	1,597	21	-	1,800	3,418
2032	2,322	18	(8)	2,000	4,333	1,613	26	-	2,000	3,639
2033	2,350	23	(8)	2,200	4,565	1,635	32	-	2,200	3,867
2034	2,375	28	(8)	2,400	4,796	1,656	40	-	2,400	4,095
2035	2,394	34	(8)	2,600	5,020	1,669	49	-	2,600	4,318
2036	2,403	41	(8)	2,600	5,036	1,675	58	-	2,600	4,333
2037	2,412	49	(8)	2,600	5,053	1,680	69	-	2,600	4,348
2038	2,416	57	(8)	2,600	5,065	1,678	80	-	2,600	4,358
2039	2,421	65	(8)	2,600	5,078	1,677	91	-	2,600	4,368
2040	2,426	73	(8)	2,600	5,091	1,677	102	-	2,600	4,379
2041	2,432	82	(8)	2,600	5,106	1,677	115	-	2,600	4,392
2042	2,438	92	(9)	2,600	5,121	1,677	128	-	2,600	4,405
2043	2,443	100	(9)	2,600	5,135	1,677	141	-	2,600	4,418
2024-2043 CAGR	**0.28%**	**25.45%**	**1.80%**	**17.39%**	**4.29%**	**0.23%**	**25.22%**	**-**	**17.39%**	**5.47%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-32: DR Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In (Grossed Up for Losses after Adjustments)
2024	11,120,257	8,387	(102,460)	-	11,530,319
2025	11,167,010	17,333	(129,533)	-	11,560,283
2026	11,191,675	27,643	(164,823)	-	11,559,961
2027	11,186,115	42,832	(176,118)	1,677,648	13,313,390
2028	11,176,083	63,623	(184,750)	5,032,944	16,825,944
2029	11,189,974	113,184	(191,770)	9,227,064	21,272,887
2030	11,189,127	213,388	(199,663)	13,421,184	25,756,481
2031	11,213,264	311,898	(208,267)	15,098,832	27,630,958
2032	11,277,178	419,046	(216,911)	16,776,480	29,556,036
2033	11,363,459	517,016	(223,265)	18,454,128	31,497,309
2034	11,429,730	618,866	(227,863)	20,131,776	33,423,545
2035	11,463,643	729,158	(230,393)	21,809,424	35,326,928
2036	11,497,139	834,090	(232,017)	21,809,424	35,470,051
2037	11,523,543	934,292	(233,213)	21,809,424	35,601,259
2038	11,518,001	1,027,523	(234,175)	21,809,424	35,692,002
2039	11,516,253	1,111,218	(235,016)	21,809,424	35,776,865
2040	11,516,626	1,184,344	(235,784)	21,809,424	35,852,966
2041	11,517,014	1,272,435	(236,700)	21,809,424	35,944,582
2042	11,518,905	1,352,836	(237,565)	21,809,424	36,029,782
2043	11,518,048	1,425,081	(239,180)	21,809,424	36,102,785
2024-2043 CAGR	**0.19%**	**31.03%**	**4.56%**	**17.39%**	**6.19%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-33: DR Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In
2024	2,320	1	(7)	-	2,314	1,603	2	-	-	1,605
2025	2,302	2	(1)	-	2,303	1,614	4	-	-	1,618
2026	2,309	4	(1)	-	2,311	1,619	6	-	-	1,625
2027	2,312	7	(9)	200	2,510	1,625	10	-	200	1,835
2028	2,332	10	(10)	600	2,933	1,643	14	-	600	2,257
2029	2,371	17	(10)	1,100	3,477	1,669	24	-	1,100	2,792
2030	2,389	28	(2)	1,600	4,015	1,692	40	-	1,600	3,332
2031	2,405	40	(2)	1,800	4,244	1,704	57	-	1,800	3,561
2032	2,428	54	(2)	2,000	4,480	1,720	77	-	2,000	3,797
2033	2,487	73	(4)	2,200	4,756	1,744	97	-	2,200	4,040
2034	2,514	89	(4)	2,400	4,999	1,766	117	-	2,400	4,283
2035	2,533	106	(4)	2,600	5,235	1,781	140	-	2,600	4,520
2036	2,544	123	(4)	2,600	5,262	1,788	160	-	2,600	4,548
2037	2,554	138	(4)	2,600	5,287	1,793	180	-	2,600	4,573
2038	2,559	152	(4)	2,600	5,306	1,792	198	-	2,600	4,590
2039	2,564	165	(5)	2,600	5,324	1,792	214	-	2,600	4,606
2040	2,569	175	(5)	2,600	5,340	1,792	227	-	2,600	4,619
2041	2,625	199	-	2,600	5,424	1,792	245	-	2,600	4,637
2042	2,631	212	-	2,600	5,444	1,793	261	-	2,600	4,654
2043	2,637	225	-	2,600	5,462	1,793	276	-	2,600	4,669
2024-2043 CAGR	**0.68%**	**30.87%**	**-**	**17.39%**	**4.62%**	**0.59%**	**29.74%**	**-**	**17.39%**	**5.78%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-34: AER Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	Other Electrification	DERs*	All-In (Grossed Up for Losses after Adjustments)**
2024	11,101,455	8,387	364,113	(110,684)	11,883,006
2025	11,146,090	19,019	436,056	(148,667)	11,976,375
2026	11,180,002	78,715	508,676	(193,922)	12,102,931
2027	11,183,726	177,807	581,469	(214,918)	14,019,846
2028	11,175,495	259,824	654,720	(233,887)	17,664,156
2029	11,188,642	310,016	727,467	(252,063)	22,175,419
2030	11,187,507	388,652	799,900	(269,098)	26,702,362
2031	11,212,225	505,329	872,112	(286,185)	28,663,126
2032	11,276,882	636,838	946,110	(302,337)	30,684,029
2033	11,362,594	784,224	1,018,064	(316,319)	32,743,703
2034	11,428,248	937,469	1,091,316	(328,362)	34,791,911
2035	11,463,205	1,091,471	1,163,947	(335,745)	36,813,024
2036	11,496,993	1,212,641	1,237,633	(341,850)	37,045,844
2037	11,523,543	1,322,595	1,308,023	(346,667)	37,257,259
2038	11,518,001	1,420,000	1,380,990	(351,519)	37,424,639
2039	11,516,253	1,503,947	1,454,377	(355,985)	37,582,749
2040	11,516,183	1,574,548	1,528,188	(360,104)	37,729,460
2041	11,516,863	1,664,493	1,603,435	(365,644)	37,897,210
2042	11,518,905	1,746,497	1,682,631	(370,751)	38,062,658
2043	11,517,598	1,821,055	1,766,567	(374,969)	38,222,704
2024-2043 CAGR	**0.19%**	**32.73%**	**8.67%**	**6.63%**	**6.34%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-35: AER Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	Other Electrification	DERs*	All-In**	Base Load	EV Load	Other Electrification	DERs*	All-In**
2024	2,319	1	54	(7)	2,368	1,604	2	58	-	1,664
2025	2,302	2	65	(1)	2,368	1,613	4	67	-	1,685
2026	2,311	10	76	(2)	2,396	1,621	14	78	-	1,712
2027	2,306	23	87	(2)	2,615	1,630	29	89	-	1,947
2028	2,328	34	98	(2)	3,058	1,649	42	103	-	2,394
2029	2,368	40	109	(2)	3,616	1,675	53	111	-	2,939
2030	2,395	52	120	(2)	4,165	1,699	69	123	-	3,490
2031	2,438	70	131	(6)	4,433	1,711	92	134	-	3,737
2032	2,465	90	141	(6)	4,690	1,729	119	150	-	3,998
2033	2,496	113	152	(6)	4,955	1,753	150	156	-	4,259
2034	2,572	143	163	-	5,278	1,776	179	167	-	4,522
2035	2,592	168	174	-	5,535	1,792	211	178	-	4,781
2036	2,604	188	185	-	5,576	1,798	198	196	-	4,792
2037	2,615	206	196	-	5,617	1,806	256	201	-	4,863
2038	2,620	221	207	-	5,648	1,806	275	212	-	4,892
2039	2,644	251	218	-	5,714	1,806	290	223	-	4,919
2040	2,650	262	229	-	5,740	1,805	259	241	-	4,905
2041	2,657	277	241	-	5,774	1,807	321	246	-	4,974
2042	2,664	291	252	-	5,807	1,808	338	258	-	5,005
2043	2,670	304	265	-	5,839	1,809	354	271	-	5,034
2024-2043 CAGR	**0.74%**	**32.97%**	**8.70%**	**-**	**4.87%**	**0.63%**	**31.44%**	**8.49%**	**-**	**6.00%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-36: AI Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	Other Electrification	DERs*	All-In (Grossed Up for Losses after Adjustments)**
2024	11,101,455	8,387	669,314	(107,059)	12,206,099
2025	11,146,090	19,019	801,429	(140,088)	12,367,602
2026	11,180,002	78,715	934,873	(182,332)	12,560,943
2027	11,183,726	177,807	1,068,683	(202,275)	14,542,797
2028	11,175,495	259,824	1,203,463	(221,902)	18,250,789
2029	11,188,642	310,016	1,337,130	(242,976)	22,822,756
2030	11,187,507	388,652	1,470,195	(264,221)	27,408,727
2031	11,212,225	505,329	1,602,857	(283,626)	29,430,309
2032	11,276,882	636,838	1,739,038	(305,764)	31,510,005
2033	11,362,594	784,224	1,871,172	(325,100)	33,627,037
2034	11,428,248	937,469	2,005,966	(342,513)	35,734,013
2035	11,463,205	1,091,471	2,139,408	(355,144)	37,813,257
2036	11,496,993	1,212,641	2,274,969	(365,028)	38,106,856
2037	11,523,543	1,322,595	2,403,959	(374,979)	38,374,208
2038	11,518,001	1,420,000	2,538,123	(384,041)	38,601,207
2039	11,516,253	1,503,947	2,673,102	(391,856)	38,820,251
2040	11,516,183	1,574,548	2,809,060	(398,365)	39,029,480
2041	11,516,863	1,664,493	2,947,074	(404,350)	39,262,430
2042	11,518,905	1,746,497	3,092,513	(409,177)	39,497,475
2043	11,517,598	1,821,055	3,246,697	(413,614)	39,730,785
2024-2043 CAGR	**0.19%**	**32.73%**	**8.67%**	**7.37%**	**6.41%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-37: AI Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	Other Electrification	DERs*	All-In**	Base Load	EV Load	Other Electrification	DERs*	All-In**
2024	2,321	1	100	(7)	2,416	1,607	2	110	-	1,718
2025	2,309	3	120	(8)	2,424	1,616	4	127	-	1,748
2026	2,314	10	134	(1)	2,457	1,624	14	148	-	1,786
2027	2,320	21	160	(11)	2,689	1,633	29	170	-	2,032
2028	2,342	30	179	(12)	3,139	1,653	42	196	-	2,492
2029	2,380	38	200	(14)	3,704	1,680	53	212	-	3,045
2030	2,400	52	211	(2)	4,260	1,704	69	233	-	3,606
2031	2,416	67	230	(2)	4,511	1,717	92	254	-	3,863
2032	2,471	90	259	(6)	4,814	1,736	119	285	-	4,140
2033	2,502	113	279	(7)	5,088	1,760	150	297	-	4,407
2034	2,578	143	299	-	5,421	1,783	179	318	-	4,680
2035	2,599	168	320	-	5,687	1,800	211	339	-	4,950
2036	2,611	188	339	-	5,738	1,808	235	373	-	5,016
2037	2,622	206	360	-	5,788	1,815	256	382	-	5,052
2038	2,646	238	364	(0)	5,848	1,815	275	403	-	5,092
2039	2,652	251	384	(0)	5,887	1,815	290	424	-	5,130
2040	2,658	262	401	-	5,921	1,766	330	501	-	5,196
2041	2,665	277	422	-	5,965	1,817	321	468	-	5,206
2042	2,672	291	443	(0)	6,007	1,819	338	491	-	5,248
2043	2,663	287	486	-	6,036	1,772	354	578	-	5,305
2024-2043 CAGR	**0.72%**	**32.57%**	**8.70%**	**-**	**4.94%**	**0.52%**	**31.44%**	**9.15%**	**-**	**6.11%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Section 4. Supply-Side Resources

NIPSCO's generation fleet is in the midst of a transition as with much of the electric industry. This section identifies NIPSCO's existing fleet of supply-side resources, describes renewable generation currently in-service and planned to be in-service, and outlines a broad mix of future potential resource options.

4.1 Existing Resources

NIPSCO has a variety of generation resources to meet its customers' forecast capacity and energy needs. Not only do these resources need to meet the principles set out in Section 1, but they must also operate within MISO, the Regional Transmission Organization, and are subject to NERC standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner, and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator, and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization Reliability standards approved by FERC. In NIPSCO's case, its Regional Reliability Organization is ReliabilityFirst.

NIPSCO's fully owned generating resources consist of coal, natural gas, hydro, wind, solar, and solar plus storage units. Additionally, NIPSCO meets its customer needs with additional wind and solar purchase power agreements and joint ventures. The total NDC of the existing resources is 3,644 MW across multiple generation sites, including Schahfer (Units 16A, 16B, 17, and 18), Michigan City (Unit 12), Sugar Creek, two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro), and Cavalry Solar plus Storage. Of the total capacity, 33% is from coal-fired units, 20% is from natural gas-fired units, and 47% is from wind, solar plus storage, and hydroelectric generation units. Table 4-1 provides a summary of the current generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity

Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	877
Sugar creek		NG	578
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	1,000
Solar + Storage		Solar + Storage	710
NIPSCO			3,644

NG=Natural Gas

4.1.1 Michigan City

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. It has one base-load unit, Unit 12, and is equipped with SCR and OFA systems to reduce NO_x emissions. An FGD system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-2.

Table 4-2: Michigan City Generating Station

	Unit 12
Net Output	
Min (MW)	310
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	Coal
Turbine	General electric
Frame	G2
In-Service	1974
Environmental Controls	FGD, SCR, OFA

4.1.2 Schahfer

Schahfer is located on an approximately 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. It is the largest of NIPSCO's generating stations. There are two coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce SO2 emissions and SCR, SNCR, LNB, and OFA systems to reduce NO_x emissions. FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. The individual unit characteristics of Schahfer are provided in Table 4-3.[62]

[62] Units 14 and 15 were retired effective October 1, 2021.

Table 4-3: Schahfer

	Unit 17	Unit 18	Unit 16A	Unit 16B
Net Output				
Min (MW)	135	135	------	------
Max (MW)	361	361	78	77
Boiler	Combustion Engineering	Combustion Engineering	-----	-----
Burners	6 Pulverizers	6 Pulverizers	-----	-----
Main Fuel	Coal	Coal	Gas	Gas
Turbine	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB243	BB243	D501	D501
In-Service	1983	1986	1979	1979
Environmental Controls	FGD, LNB, OFA	FGD, LNB, OFA	-----	-----

4.1.3 Sugar Creek

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired CTs and CCGTs were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008 and is its newest thermal electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two generators and one steam turbine generator are operated in the CCGT mode, and environmental control technologies include SCR to reduce NO_x, and dry low NO_x combustion systems. Sugar Creek completed an AGP tech upgrade in the fall of 2023. This upgrade included a new thermal barrier coating for combustion turbine components, which enhanced the overall production capabilities of the combustion turbines. Subsequent RATA and GVTC testing was performed post-outage to validate the new capability and unit ratings. The individual unit characteristics of Sugar Creek are provided in Table 4-4.

Table 4-4: Sugar Creek

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	112	112	112
Max (MW)	175	175	228
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA.04	7FA.04	D11
In-Service	2002	2002	2003
Environmental Controls	SCR,DLN	SCR,DLN	---

4.1.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources)

Norway Hydro is located near Monticello, Indiana, on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has four generating units capable of producing up to 7.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 4-5.

Table 4-5: Norway Hydro

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydro is located near Monticello, Indiana, along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has three generating units capable of producing up to 9.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 4-6.

Table 4-6: Oakdale Hydro

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

Calvary Solar + Storage is located in White County, Indiana, and was originally approved in Cause No. 45462 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Cavalry Energy Center, LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 45936 and went into commercial operation in May 2024. The individual unit characteristics of Cavalry are provided in Table 4-7.

Table 4-7: Cavalry Solar + Storage

	Cavalry
Solar Output	
Total Output (MW)	200
Storage Output	
Total Output (MW)	45
Output Period (Hrs.)	4
Discharge Limits (Cycles/Yr.)	100
In-Service	2024
Main Fuel	Solar + Storage

4.1.5 NIPSCO Wind and Solar Purchase Power Agreements and Joint Venture

NIPSCO is also engaged in a 20-year PPA with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Jordan Creek, which will operate and maintain the facilities. Jordan Creek is located in Benton and Warren counties, Indiana, near Williamsport, Indiana, and went into commercial operation in December 2020. The individual unit characteristics of Jordan Creek are provided in Table 4-8.

Table 4-8: Jordan Creek Wind PPA

	Jordan Creek PPA		
NET Output			
Per Unit (MW)	2.8	2.3	2.5
Number of Units	131	14	1
Total Output (MW)	369	32	2.5
In-Service	2020		
Main Fuel	Wind		

The Rosewater wind project, developed and constructed by EDP Renewables North America LLC, is located in White County, Indiana, and went into commercial operation in December 2020. EDP Renewables and NIPSCO entered into a joint venture and ownership agreement for the Rosewater project. The individual unit characteristics of Rosewater are provided in Table 4-9.

Table 4-9: Rosewater Wind JV

	Rosewater JV
NET Output	
Per Unit (MW)	4
Number of Units	25
Total Output (MW)	100
In-Service	2020
Main Fuel	Wind

Indiana Crossroads, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana, and went into commercial operation in January 2021. The individual unit characteristics of Indiana Crossroads are provided in Table 4-10.

Table 4-10: Indiana Crossroads Wind I JV

Indiana Crossroads Wind JV	
Net Output	
Per Unit (MW)	4.2
Number of Units	72
Total Output (MW)	300
In-Service	2021
Main Fuel	Wind

The Dunns Bridge I Solar project, developed and constructed by NextEra Energy Resources, LLC, is located in Jasper County, Indiana, and went into commercial operation in August 2023. The individual unit characteristics of Dunns Bridge I are provided in Table 4-11.

Table 4-11: Dunns Bridge I Solar JV

	Dunns Bridge I JV
Solar Output	
Total Output (MW)	265
In-Service	2023
Main Fuel	Solar

The Indiana Crossroads Solar project, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana, and went into commercial operation in August 2023. The individual unit characteristics of Indiana Crossroads Solar are provided in Table 4-12.

Table 4-12: Indiana Crossroads Solar JV

	Indiana Crossroads Solar JV
Solar Output	
Total Output (MW)	200
In-Service	2023
Main Fuel	Solar

NIPSCO is engaged in a 15-year PPA starting in 2023 with EDP Renewables North America, LLC, in which NIPSCO will purchase the power directly from Indiana Crossroads II Wind, who will operate and maintain the facility. Indiana Crossroads II Wind, located in White County, Indiana, and went into commercial operation in December 2023. The individual unit characteristics of Indiana Crossroads II Wind are provided in Table 4-13.

Table 4-13: Indiana Crossroads II Wind PPA

Indiana Crossroads II Wind PPA		
Net Output		
Per Unit (MW)	4.2	5.6
Number of Units	6	32
Total Output (MW)	25.2	179.2
In-Sevice	2023	
Main Fuel	Wind	

4.1.6 Total Resource Summary

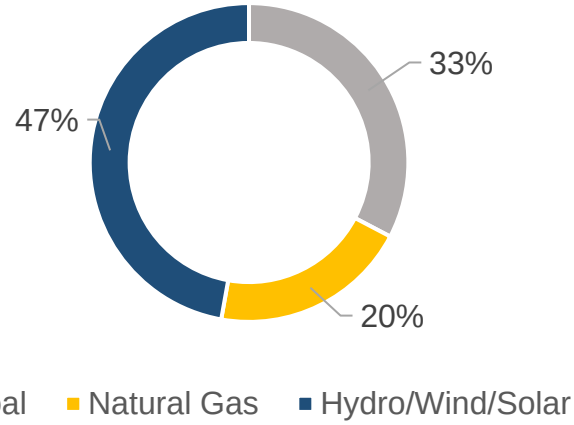
Table 4-14 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-1 illustrates NIPSCO's existing resources by fuel type.

Table 4-14: Existing Generating Units

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
		Subtotal	877	
Sugar creek		NG	578	2002
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind	Rosewater	Wind	100	2020
	Jordan Creek	Wind	400	2020
	Indiana Xrds I	Wind	300	2021
	Indiana Xrds II	Wind	200	2023
		Subtotal	1,000	
Solar + Storage	Dunns Bridge I	Solar	265	2023
	Indiana Xrds	Solar	200	2023
	Cavalry	Solar + Storage	245	2024
		Subtotal	710	
NIPSCO			3,644	

NG=Natural Gas

Figure 4-1: Existing Resources Net Demonstrated Capacity



4.2 Fuel, Energy, and Capacity Procurement Strategy for Existing Resources[63]

As NIPSCO operates as a public utility providing reliable electric service to customers, the procurement of fuel, energy, and capacity at the lowest reasonably possible cost is the foundation of NIPSCO's strategy. NIPSCO's Fuel Supply team ensures all fuel, energy, and capacity supply meets the requirements of Indiana Code § 8-1-2-42(d).

4.2.1 Coal Procurement and Inventory Management Practices

4.2.1.1 Coal Supply Strategy

NIPSCO employs a multifaceted strategy to execute coal procurement activities associated with the fuel supply requirements for its coal-fired units. The goal of this strategy is to maximize reliability while maintaining customer affordability. Key elements include: (1) procuring coal supply from sources that minimize the delivered cost of coal, O&M costs, environmental costs, inventory costs, and other financial impacts ("total cost of ownership"); (2) hedging customers' price exposure with forward purchases to protect against price volatility; (3) supporting environmental compliance; (4) maintaining reliable inventory levels; (5) ensuring reliability of coal supply and delivery; and (6) maximizing operational flexibility and reliability by procuring coal types that can be used in more than one unit whenever possible.

[63] Due to the timing of the IRP, this section was written during the summer of 2024 and the market overview is based on the market conditions at that time. The IRP is an imperfect snapshot in time and changes in market conditions may occur. At the time of submission of the IRP, it is unknown how long current trends will continue. As always, NIPSCO will continue to monitor the markets and adjust procurement plans as necessary.

4.2.1.2 Coal Procurement

NIPSCO maintains a five-year baseline coal forecast that is used to create a strategy that drives its fuel procurement plan. The forecast is used to estimate coal and related coal transportation procurement requirements needed to maintain reliable and economic coal inventory levels. The strategy and fuel procurement plan are highly dynamic and are updated on a periodic basis in response to energy market conditions. Over the past several years, environmental regulations, a significant influx of highly variable renewable generation (e.g., wind and solar), low natural gas prices, and energy efficiency and other demand-side initiatives have made coal-fired generation the marginal supply source. Consequently, this has created an environment with highly variable and nearly unpredictable coal purchase requirements. Therefore, NIPSCO's fuel procurement plans must remain as flexible as possible while still maintaining supply reliability. Obtaining volume flexibility can be challenging since coal suppliers and transportation providers typically require firm volume commitments.

4.2.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Over the last decade, energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower production costs and highly efficient natural gas extraction processes (horizontal drilling and fracking) have kept natural gas a competitive fuel when used in high-efficiency CCGT units. In addition, increases in wet gas production to gather petroleum liquids further increase natural gas supply when oil prices rise.

These market dynamics displaced a significant amount of coal-fired electric generation and have kept coal prices relatively low. In addition, the acceleration of coal unit retirements nationwide further decreased coal demand, and higher mining costs driven by government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies over the last few years. The restructuring of coal companies' debt and other costs through the bankruptcy process has allowed some of these coal companies to continue coal production in this competitive environment. Class I railroads have also realized that their rates must be rationalized to allow coal to compete in this environment. Supply has been reduced, and any significant increase in demand could result in coal price volatility. This became evident in early 2022 through mid-2023 as energy shortages in Europe cascaded through global markets. In addition, post-pandemic consumer demand recovery, increased energy demand, and railroad union labor disputes caused significant rail transportation disruptions domestically.

These factors led to a myriad of supply chain challenges globally and contributed to a spike in coal prices and related coal transportation rates as Europe increased coal imports and U.S. coal demand increased while supply reliability decreased. This has since reversed, and pricing has

fallen back to pre-2022 levels. Going forward, several factors will likely limit the upside for coal prices in the long run. The first factor is the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal-fired electric generation. A second factor is the continuation of coal-fired generation retirements, which will continue to reduce coal demand. Lastly, the competitiveness of natural gas generation and renewables will likely limit demand for coal.

Competition in energy markets has also driven a shift in coal supply regions over the last several years. Specifically, the relatively high cost to produce coal in the Central Appalachian regions and low coal prices have resulted in declining coal production and this has increased market share of the lower-cost ILB region. Even with its higher sulfur content, ILB coal has become an export resource, and its use has increased domestically as utilities have installed FGDs to meet tighter SO_2 limits and other emission standards. Some utilities in the Southeast are now using ILB coal, which replaced higher cost Columbian and Central Appalachia coal.

The PRB in Wyoming and Montana is the largest coal producing basin in the United States. PRB coal has a lower heat content than coals mined in other basins; however, some utilities have units designed to efficiently utilize lower cost PRB coal, and over the last 30 years, a number of utilities retrofitted older coal units to use PRB coal in a blend with either Central Appalachian, ILB, or NAPP coals to reduce their overall fuel costs and lower SO_2 emissions. U.S. coal exports have declined 1.6% annually over the last 10 years. India's demand for U.S. coal has grown on average by 20% annually over the same period offsetting declines in European demand.

In general, most export tonnage originates from Central Appalachian, ILB, and NAPP coal regions for metallurgical and steam coal markets abroad. Coal suppliers rely on international markets to offset losses in domestic markets; however, the pressure to reduce coal use worldwide, except for China and India, will likely reduce international demand in the long run as well.

Overall, these fundamentals are bearish for long-term coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices and incorporate in its procurement strategies.

4.2.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Domestic demand for coal has continued to trend lower over the last several years; therefore, prices are expected to remain relatively low and stable. NAPP coal and ILB coal market pricing spiked to record highs in 2022 but has fallen back to near historic lows and has been relatively flat. Pricing for PRB coal pricing spiked at the end of 2021, but also fell back to levels close the marginal cost of production and have remained relatively flat.

Domestic and international coal prices increased during 2021 as the economic recovery from the 2020 pandemic caused a surge in demand and prices spiked in 2022 due to the Ukraine-Russian conflict. Export dynamics can drive pricing modestly higher for some coal types (e.g., NAPP and ILB) when global demand increases as well; however, the long-term trends for both demand and pricing are bearish.

4.2.1.5 Coal and Issues of Environmental Compliance

Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to evolve in a manner that meets current and future environmental requirements.

4.2.1.6 Maintenance of Coal Inventory Levels

NIPSCO has an ongoing strategy to maintain stable coal inventories and reviews inventory targets levels annually. NIPSCO may adjust inventory targets to account for changes in coal supply availability, transportation constraints, unit consumption, energy pricing, and to account for coal unit retirements. NIPSCO may modify target inventory levels on a unit-by-unit basis depending on the consumption, delivery rates, reliability of coal supply, station coal handling operations, and retirement plans. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates, variability in delivery performance, and higher energy market prices generally require higher levels of inventory to ensure reliability and minimize customer cost.

4.2.1.7 Forecast of Coal Delivery and Transportation Pricing

To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts that consider historical, current, and future coal supply requirements. All fuel procurement options are compared on a delivered cost basis, which includes a complete evaluation of all potential costs (e.g., operational, environmental, handling, etc.) and logistical considerations.

Coal deliveries have been somewhat stable from the various supply regions. Railroads typically make investment in infrastructure and equipment to support anticipated shipment rates. The cyclical nature of the railroad business can create short-term transportation constraints and can impact NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years. The decline in coal demand has made it difficult for railroads to invest in coal infrastructure, and this may lead to transportation constraints if there is a significant increase in overall coal demand.

Transportation rates have remained relatively flat over the last several years given the competition in the energy markets. Railroads have been willing to rationalize rail rates to remain competitive in the energy market. This pricing trend has kept NIPSCO's coal-fired generation competitive to a certain extent.

4.2.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options from various supply regions for most of its coal transportation moves and is further disadvantaged due to its geographical location. Not only are rail transportation options limited, other transport modes (trucking, barging, and lake vessels) are not economically or logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one Class I railroad. All coal deliveries by this railroad to Schahfer

have been transported under agreements with escalating transportation rates plus a fuel surcharge indexed to oil prices. Beginning in 2017, NIPSCO and this railroad worked to develop a creative, market-based indexed agreement that lowered rates to improve the station's competitiveness in the market. A second indexed rate agreement has also been adopted with another railroad. As stated above, energy markets have forced a rationalization of coal pricing and associated transportation costs. NIPSCO expects this dynamic to continue for the foreseeable future.

As a result of these changes in the energy markets and agreement structures, NIPSCO's PRB and ILB coal transportation rates have declined in real terms since 2017. Fuel surcharges continue to fluctuate with the changes in oil prices. Transportation pricing is expected to remain soft as long as energy prices stay low and relatively flat over the next five years. Increases in transportation fuel charges could lead to modest transportation cost increases if oil prices trend higher.

4.2.1.9 Coal Contractual Flexibility, Deliverability, and Procurement

Contract terms for coal and coal transportation agreements range from one to five years in duration. Spot coal purchases are made on an as-needed basis to manage inventory fluctuations. Fuel blending strategies can be adjusted to conserve a particular type of coal if supply problems are experienced. In addition, coal suppliers and railroads have been more amenable to providing some volume flexibility, including lower minimum volume obligations or elimination of minimum volume obligations entirely. This flexibility has supported NIPSCO's inventory management efforts.

4.2.2 Natural Gas Procurement and Management

NIPSCO currently procures natural gas for its CCGT generating station using a natural gas supply contract with an energy manager that delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on Midwestern Gas Transmission Company interstate pipeline and releases the capacity to the energy manager. The contract has provisions to purchase next day and intraday firm gas supplies to serve the daily needs of the facility. NIPSCO nominates and balances the gas supply needs of the CCGT generating station. A portion of the gas supply for Sugar Creek is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

The coal units and CTs at NIPSCO are located within the NIPSCO natural gas local distribution company service territory. NIPSCO maintains a separate contract for firm delivered natural gas supply and energy management for these units. The contract has provisions to nominate next-day usage based on the expected usage of each generating station. The actual usage is balanced daily, and balancing is the responsibility of the energy manager.

4.2.3 Electric Generation Gas Supply Request for Proposal Process

NIPSCO conducts two separate RFPs for the electric generation firm natural gas supply, one for the Sugar Creek facility and a separate one for the coal units and CTs. The RFP process may be done on a seasonal or annual basis, depending on the current contract length and supplier agreement. The process includes qualifying potential suppliers, customizing the RFP based on near-term system needs and gas supply trends. Suppliers are chosen based on the overall value of the package and ability to serve the needs of the facility. To date, NIPSCO has entered into electric generation gas supply agreements that extend no longer than two years but is always evaluating the value and benefits of longer-term agreements.

4.3 Planned Resource Summary

In addition to its existing resource portfolio, NIPSCO has a number of planned renewable resource projects with expected in-service dates through 2025. The planned projects have been filed with the Commission and are in various stages of development. The projects are summarized in Table 4-15.

Table 4-15: Planned Renewable Projects

Project	Technology	Expected ICAP (MW)	Battery Capacity (MW)	Expected In -Service
Carpenter	Wind	200	-	2025
Templeton	Wind	200	-	2027
Dunns Bridge II	Solar + Storage	435	56.25	2024
Green River	Solar	200	-	2024
Fairbanks	Solar	250	-	2025
Gibson	Solar	200	-	2025
Appleseed	Solar	200	-	2025
Total		1,685	56.25	

4.3.1 Planned Wind Resources

NIPSCO has entered into a 20-year PPA starting in 2025 with EDP Renewables North America, LLC, in which NIPSCO will purchase the power directly from Carpenter Wind, which will operate and maintain the facility. Carpenter Wind, located in Jasper County, Indiana, is expected to go into commercial operation by December 2025. The planned unit characteristics of Carpenter Wind are provided in Table 4-16.

Table 4-16: Carpenter Wind PPA

Carpenter Wind PPA		
Net Output		
Per Unit (MW)	4.5	4.3
Number of Units	33	12
Total Output (MW	148.5	51.6
In-Service	2025	
Main Fuel	Wind	

The Templeton wind project, currently under development by NextEra Energy Resources LLC, located in Benton County, Indiana, is expected to go into commercial operation in June 2027. It was originally contracted as a PPA with a 2025 in-service date and approved in Cause No. 45887 but has since been converted to a BTA. The individual unit characteristics of Templeton are provided in Table 4 17.

Table 4-17: Templeton Wind BTA

	Templeton Wind BTA
Net Output	
Per Unit (MW)	2.82
Number of Units	71
Total Output (MW)	200.22
In-Service	2027
Main Fuel	Wind

4.3.2 Planned Solar and Solar + Storage Resources

NIPSCO has five planned solar projects, one of which includes additional battery storage, that are expected to be in service by 2025.

Dunns Bridge II Solar + Storage is located in Jasper County, Indiana, and was originally approved in Cause No. 45462 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Dunn's Bridge II Solar and Storage Generation LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 45936 and will go into commercial operation in January 2025. The planned unit characteristics of Dunns Bridge II are provided in Table 4-18.

Table 4-18: Dunns Bridge II Solar + Storage

	Dunns Bridge II
Solar Output	
Total Output (MW)	435
Storage Output	
Total Output (MW)	56.25
Output Period (Hrs.)	4
Discharge Limits (Cycles/Yr.)	100
In-Service	2025
Main Fuel	Solar + Storage

NIPSCO has entered into a 20-year PPA starting in 2025 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Green River, which will operate and maintain the facility. Green River, located in Breckenridge and Meade counties, Kentucky, is expected to go into commercial operation by June 2025. The planned unit characteristics of Green River are provided in Table 4-19.

Table 4-19: Green River Solar PPA

	Green River PPA
Solar Output	
Total Output (MW)	200
In-Service	2025
Main Fuel	Solar

Fairbanks Solar is located in Sullivan County, Indiana, and was originally approved in Cause No. 45511 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Fairbanks Solar Generation, LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 46028 and will go into commercial operation in May 2025. The planned unit characteristics of Fairbanks are provided in Table 4-20.

Table 4-20: Fairbanks Solar

	Fairbanks Solar
Solar Output	
Total Output (MW)	250
In-Service	2025
Main Fuel	Solar

Gibson Solar is located in Gibson County, Indiana, and was originally approved in Cause No. 45926 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Gibson Solar Generation, LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 46032 and will go into commercial operation in July 2025. The planned unit characteristics of Gibson are provided in Table 4-21.

Table 4-21: Gibson Solar

	Gibson Solar
Solar Output	
Total Output (MW)	200
In-Service	2025
Main Fuel	Solar

NIPSCO has entered into a 20-year PPA starting in 2022 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Appleseed, which will operate and maintain the facility. Appleseed, located in Cass County, Indiana, is expected to go into commercial operation by December 2025. The planned unit characteristics of Appleseed are provided in Table 4-22.

Table 4-22: Appleseed Solar PPA

	Appleseed Solar PPA
Solar Output	
Total Output (MW)	200
In-Service	2025
Main Fuel	Solar

4.4 MISO Wholesale Electricity Market

MISO supplies an important element to NIPSCO's long-term plans. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. In 2023, MISO has members from 15 states and one Canadian province with a generation capacity of 191,000 MW and 75,000 miles of high-voltage transmission. MISO manages one of the world's largest energy and operating markets that includes a Day-Ahead Market, Real-Time Market, and Financial Transmission Rights Market.

4.4.1 Operations Management and Dispatch Implications

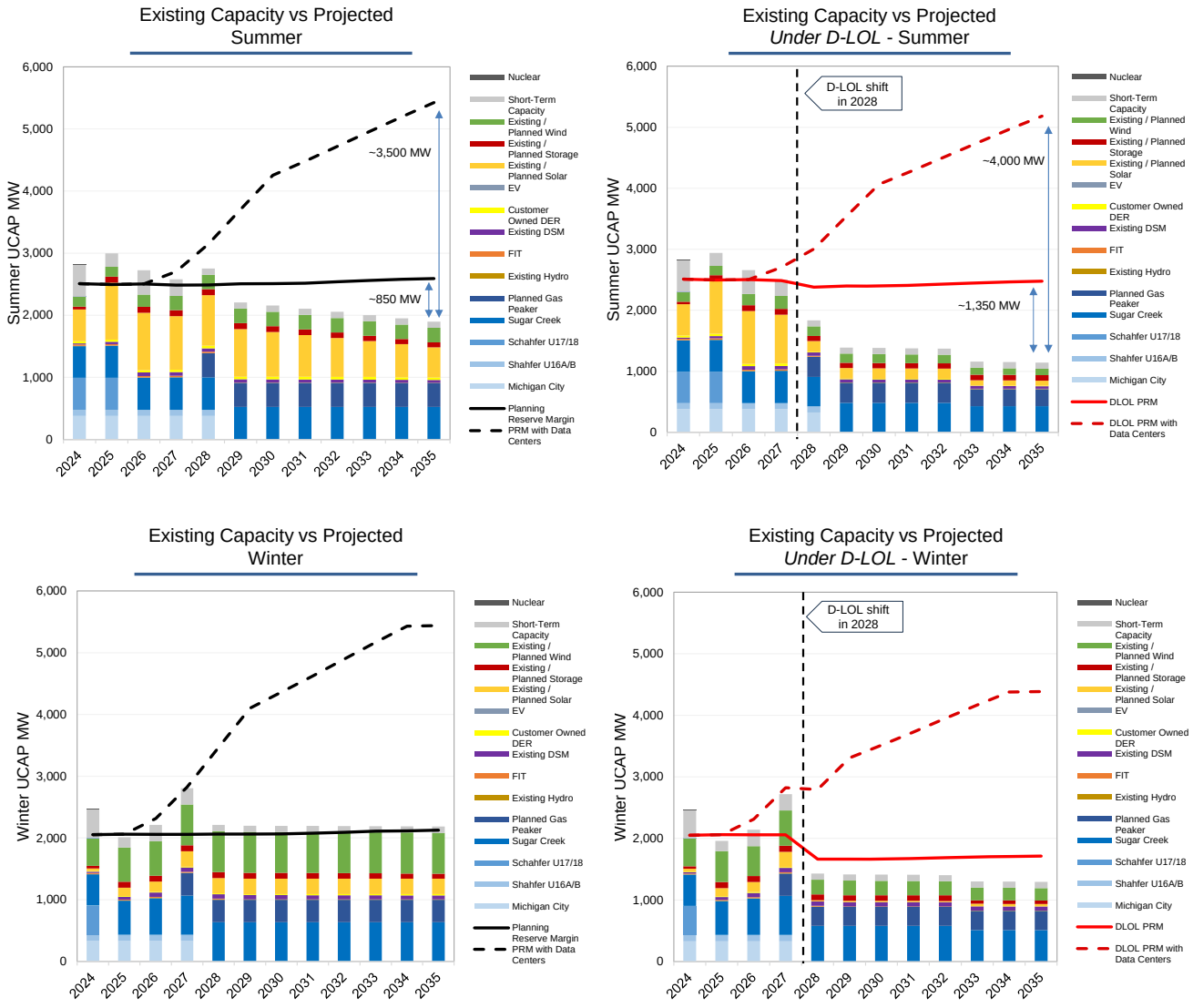
The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, environmental considerations, and the overall generation mix within MISO may affect the level of future dispatch.

4.5 Resource Adequacy and Current Supply-Demand Balance

Consistent with the principles set out in Section 1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse, and affordable supply. As part of the Resource Adequacy planning process, NIPSCO utilizes the peak demand forecast coincident with MISO peak demand to determine its capacity requirements across each of the four MISO planning seasons. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks.

With the onset of MISO's seasonal resource adequacy construct, NIPSCO now needs to track reserve margin compliance across four seasons. In addition, as renewable resources become a greater share of the broader MISO market system, the seasonal capacity credit will likely change over time and will need to be monitored, particularly in light of MISO's recent D-LOL filing, which proposes a new methodology for resource accreditation and load serving entity obligations. (See Section 2 for more information related to MISO's D-LOL filing, which FERC approved in October 2024.) NIPSCO's assessment of its existing and planned resources against the future needs of its customers for both the summer and winter seasons under current market rules expectations and the new D-LOL construct is shown in Figure 4-2. Note that NIPSCO's 2024 IRP is assessing all four seasons, but summer and winter are shown for simplicity.

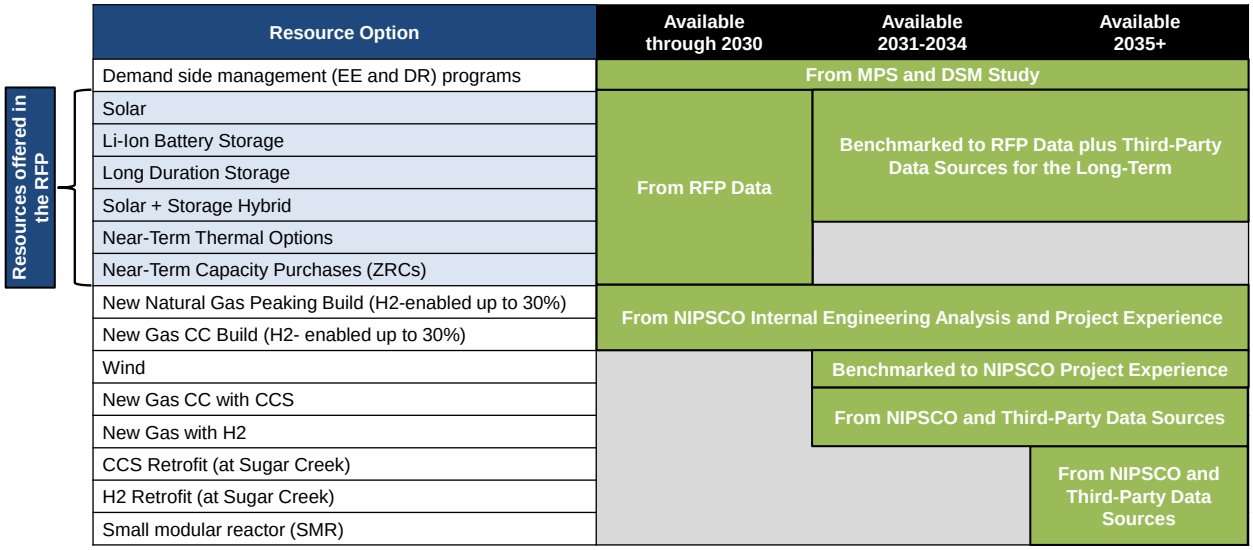
Figure 4-2: Resource Adequacy Assessment



4.6 Future Resource Options

NIPSCO developed cost, operational, and availability assumptions for a comprehensive set of new resource options using information from actual market data received via Requests for Proposal, internal engineering analysis and project experience, and third-party data sources, along with the demand side management study documented further in Section 5. A summary of all resource options, their assumed availability, and their source of key cost and operational assumptions is provided in Figure 4-3, with the remainder of this section providing additional supporting detail.

Figure 4-3: Overview of New Resource Options



4.6.1 Request for Proposal

As demonstrated in the 2024 IRP, the cost and operational estimates for future resource options modeled in the IRP should reflect the best available market data. In 2024, NIPSCO worked with CRA's Energy practice during the spring and early summer of 2024 to conduct four separate RFP events covering all sources. NIPSCO provided the RFP design summary to stakeholders on April 23, 2024, and solicited feedback. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the RFP events on May 1, 2024. The bid windows were RFP-specific, but all were closed by June 20, 2024. During NIPSCO's second Public Advisory meeting on June 24, 2024, CRA reviewed for stakeholders the RFP design and timeline and presented a preliminary assessment of the level of interest in the set of RFP.

The RFPs provided several guidelines to bidders, which are summarized below:

- Technology: The RFPs requested all solutions regardless of technology.
    - Event 1: RFP for intermittent resources including renewables and renewable paired with storage, located in LRZ6;
    - Event 2: non-intermittent resource RFP for LRZ6 resources;
    - Event 3: RFP for Bridge Resources including facilities offering near-term energy and capacity options located in LRZ6 or the broader MISO region; and
    - Event 4: RFP for up to 10 MW of Distributed Energy Resources.

- Size: Each solicitation included an estimate of the overall need, 400 MW, 600 MW, 1,000 MW, and 10 MW for RFPs 1 through 4, respectively. There were no specific size restrictions on individual projects or restrictions at the bidder levels.

- Ownership Arrangements: The RFPs were open to asset purchases (new or existing) and PPAs. However, they required that resources qualify as MISO internal generation (i.e., not pseudo-tied into MISO).

- Duration: Aside from RFP 3, Bridge Resources, the RFPs requested delivery beginning in 2027, 2028, and 2029, but indicated that alternative deliveries would be evaluated. The minimum contractual term and/or estimated useful life was requested to be five years. For RFP 3, NIPSCO was targeting resources available within 18-36 months and would consider durations as short as three years.

- Deliverability: For the All-Source RFP (RPF 1 and RFP 2), NIPSCO required that bidders have physical deliverability utilizing Network Resource Integration Service to MISO LRZ6. RFP 3 allowed for resources within the broader MISO region. RFP 4, for DER resources, considered distribution interconnected options.

- Participants and Pre-Qualification: The RFPs required counterparties be credit-worthy to ensure an ability to fulfill future resource obligations.

Overall, the RFPs generated a large amount of bidder interest, with 116 total proposals received across a range of deal structures. Within those 116 proposals, NIPSCO received bids for 58 individual projects across five states/regions with over 9.63 GW of ICAP represented.[64] Many of the proposals offered variations on pricing structure and term length, and the majority of the projects were in various stages of development. A summary of the total number of proposals received by technology type is shown in Figure 4-4.

Figure 4-4: Summary of Number of Proposals Received by Technology Type

Deal Structure	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Wind	Total
Asset Sale	1	2	12	2	-	-	17
PPA/Toll	20	12	26	6	7	-	71
Asset Sale + PPA/Toll	1; 1	4; 4	9; 9	-	-	-	14 (28)
Total Count	23	22	56	8	7	-	116*
Locations	IN, KY	IN, KY	IN, KY	IN, PA	LRZ4, PJM	-	

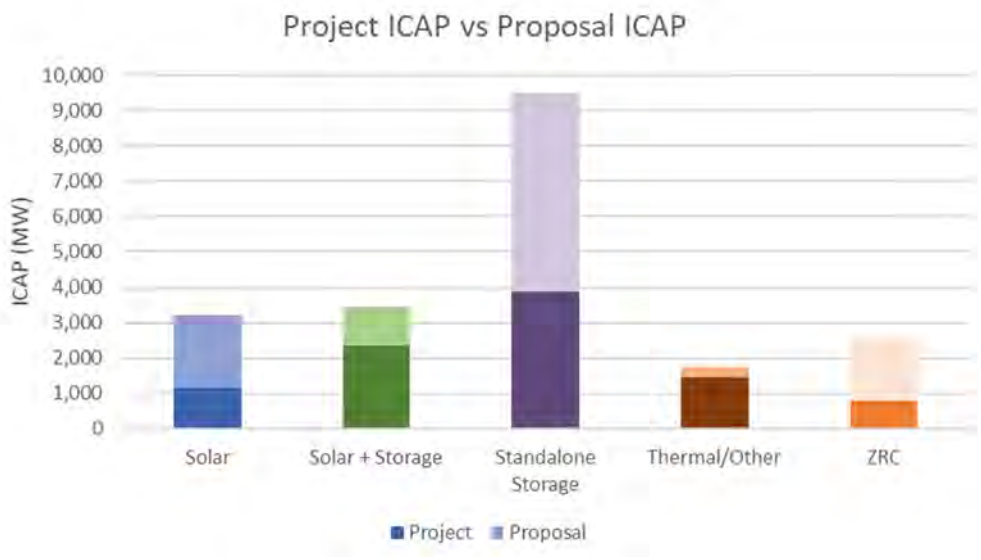
**Proposal count includes mutually exclusive projects. Projects offered as both Asset Sale and PPA/Toll are counted in the total as two proposals.*

On a total MW basis, 20.53 GW of proposals were submitted into the RFP, some of which were mutually exclusive. The 20.53 GW value represents multiple contract options for 58 projects with a total ICAP of 9.63 GW, providing a sufficiently large set of candidate options for NIPSCO to evaluate for capacity needs during the RFP delivery window. Because MISO is moving to a

[64] CRA received a bid package from one bidder following the formal bid deadline. This bid included 3 proposals for 2 separate storage facility options.

seasonal construct for capacity credit, the UCAP value of each bid is dependent on the type of facility and MISO's final seasonal capacity metrics. Figure 4-5 shows a summary of total MW offered in response to the RFPs by type.

Figure 4-5: Total MW of Proposals Received by Technology



Most PPA offers were relatively long in duration, with the majority of proposals offering contracts for 15-year terms or longer. Several bidders offered shorter-term options, including a number that provided NIPSCO with options to select from multiple duration possibilities. Figure 4-6 provides a summary of the total ICAP MW offered by duration.

Figure 4-6: Summary of Proposals Received by PPA Duration (ICAP MW)

Proposal MW ICAP by PPA Term Length (PPA or Both) and Technology

Term (Years)	Solar	Solar + Storage	Standalone Storage	Thermal/Other	ZRC	Wind	Total (MW)
1	-	-	-	-	800	-	800
2	-	-	-	150	800	-	950
3	-	-	-	-	800	-	800
4	-	-	-	-	200	-	200
5	-	-	-	450	-	-	450
6-15	201	300	796	-	-	-	1,297
>15	2,690	2,158	4,726	1,050	-	-	10,624
Total	2,891	2,458	5,522	1,650	2,600	-	**15,121**

Most importantly, the responses to the RFPs provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was relatively consistent with past NIPSCO RFPs subject to market adjustments. This indicated that technology change and developer activity in a competitive process are dynamic forces that

influence the costs of resource options for NIPSCO in the future. NIPSCO provided a summary of the various proposals by type and by price in NIPSCO's second Public Advisory meeting, with additional detail on bid price offered in Section 4.6.2 of this 2024 IRP report.

4.6.1.1 Storage at NIPSCO Sites in the RFP

As part of the All-Source RFP (RFP 1 and RFP 2), the Company requested support for potential development of storage resources located at existing NIPSCO renewable sites. Current, high-priority sites include Schahfer, Michigan City, Dunns Bridge I and II, Cavalry, Gibson, and Fairbanks. Through the RFP, NIPSCO provided interested developers available information to support potential development. NIPSCO anticipates using generator replacement at Schahfer and Michigan City associated with storage development. As a result, both would require NIPSCO asset ownership of storage assets, although ownership structures other than a BTA were considered acceptable. For other sites, NIPSCO intends to use surplus interconnection service and while not technically required, NIPSCO expressed a strong preference for ownership bids.

The RFP generated proposals from seven (7) bidders for development options related to storage at NIPSCO renewable sites. Eleven (11) facilities representing 1,512 MW were submitted for consideration.

4.6.1.2 Long-Duration Storage in the RFP

Although a large majority of storage bidders in the RFP offered four-hour duration lithium-ion battery storage technologies, longer-duration storage technologies may become more viable over the long term in order to balance diurnal variations in renewable energy resources as well as variations in demand from weekends (low demand) to weekdays (high demand). The technology can also provide needed capacity during longer-duration weather events, such as snowstorms, extended cloud cover, or wind droughts that could last for several days.

NIPSCO received long-duration storage bids from three participating bidders. All submissions were for asset sales and based on the following technologies:

- **Iron-Air storage** is a technology that promises multi-day energy storage capability. Proposals stated the potential for up to 100 hours of storage based on reversible oxidation principles. The principle of operation is static, reversible rusting. Each cell consists of iron anodes and air cathodes submerged in water-based, non-flammable alkaline electrolyte. While discharging, the battery converts iron metal to rust using oxygen from ambient air. While charging, an electrical current converts the rust back to iron, releasing oxygen.

- **Compressed CO2** technology involves the compression of gaseous CO2, which heats it. Passing it through a heat exchanger and a thermal store cools the supercritical carbon dioxide gas enough to liquify it. The liquid CO2 can be stored in this state indefinitely in pressurized cylinders. When energy is required, the CO2 is passed back through the heat exchanger, where it is warmed by recovering heat from the heatstore and reverts to high-pressure gas. The gas is used

to drive a turbine to generate electricity as it passes back into the low-pressure store, completing the closed cycle.

4.6.2 Incorporation of the RFP Results into the IRP

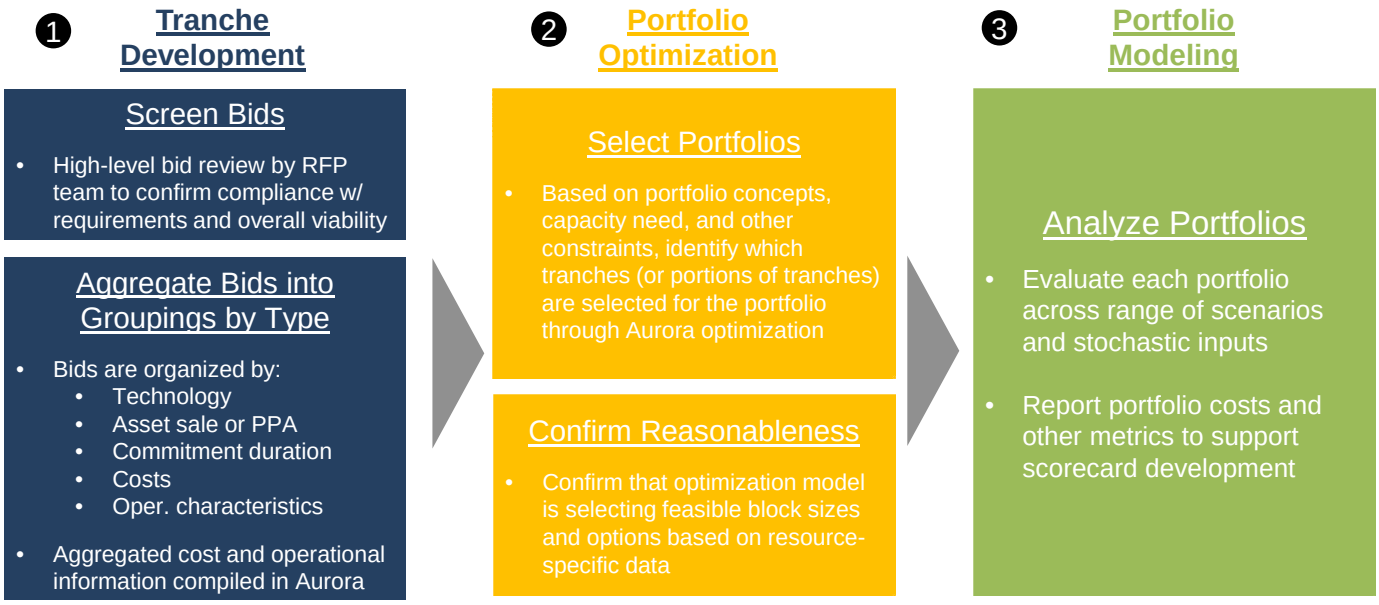
After gathering the bidder data from the RFP, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for RFP-IRP integration, which is outlined in Figure 4-7:

(1) Tranche Development: Screen bids for viability and organize the various bids into groupings or tranches according to technology, whether the bid offered a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics.

(2) Portfolio Optimization: Perform portfolio optimization analysis based on NIPSCO's potential capacity need and other portfolio design constraints (as discussed in more detail in Section 9), confirming option viability based on feasible block sizes of tranche data from the RFPs.

(3) Portfolio Modeling: Analyze comprehensive portfolios with selected tranches from the portfolio optimization step and other resource options and analyze them across the full set of scenarios and stochastic inputs.

Figure 4-7: Tranche Development and Assessment Process



4.6.2.1 Tranche Development

It was determined that a tranche approach would be most effective in aggregating the numerous data points from the RFPs into usable IRP information for three main reasons:

- The IRP is intended to select the best resource mix and future portfolio concept rather than select specific assets or projects. While the IRP analysis can now be highly informed by actionable data from the RFPs, it is only meant to develop a planning-level recommended resource strategy. NIPSCO determined that asset-specific selection would require an additional level of diligence, including assessment of development risk, evaluation of locational advantages or disadvantages for specific projects, and review of transmission system impacts, to be conducted outside of the standard IRP process.

- The IRP is a highly transparent and public process that requires sharing of major inputs with stakeholders and the public. There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data.

- The IRP modeling is complex, and resource grouping improves the efficiency of the process. Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set would improve the efficiency of setup and runtime.

When developing tranches, the CRA RFP team first organized resources by technology and then sorted them into categories according to whether they were offered as asset sales or PPAs. Projects were screened by the RFP team to determine conformity with bid requirements, and any nonconforming bids were eliminated. Duplicate projects that were offered multiple times under different structures were consolidated into the lowest-cost option to avoid double-counting. Beyond the initial organization and screening, the bids were then arranged by commitment duration and finally costs and operational characteristics.

Ultimately, the tranche development process resulted in the production of 29 total tranches. These are summarized by resource type Figure 4-8, Figure 4-9, Figure 4-10, and Figure 4-11. Note that in instances where single bids were used to develop tranche-level cost information, redactions have been made for the public version of this report.

Figure 4-8: Summary of Stand-Alone Storage RFP Tranches

	Installed Capacity (MW)	In-Service Year[1]	Storage Duration (Hours)	Round Trip Efficiency	PPA Price ($/kW-mo)	PPA Term (Years)	Asset Sale Price ($/kW)	ITC Assumption	Fixed O&M (2024 $/kW-yr)2
Storage PPA 1	768	2028	4	85%	$11.99	20	*N/A*	*N/A*	*N/A*
Storage PPA 2	200	2028	4	85%	$14.95	20	*N/A*	*N/A*	*N/A*
Storage PPA 3	261	2027	4	85%	$15.59	20	*N/A*	*N/A*	*N/A*
Storage PPA 4	166	2029	4	85%	$16.85	20	*N/A*	*N/A*	*N/A*
Storage Sale 1	1,750	2028	4	85%	*N/A*	*N/A*	$1,534	40%	$40
Storage Sale 2	900	2028	4	85%	*N/A*	*N/A*	$2,144	40%	$40
Storage Sale 3	18	2027	10	75%	*N/A*	*N/A*	***Redacted – single bid / tech data***	40%	***Redacted – single bid / tech data***
Storage Sale 4	100	2028	100	35%	*N/A*	*N/A*		40%	
DER Storage PPA	10	2027	4	85%	***Redacted – single bid***	20	*N/A*	*N/A*	*N/A*

Notes:
Each tranche listed represents a group of mutually exclusive projects, and certain cost data has been redacted, since it was developed from single RFP bids.
1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.
2: Baseline assumptions from NREL ATB used for tranche modeling purposes.

Figure 4-9: Summary of Solar RFP Tranches

	Installed Capacity (MW)	In-Service Year[1]	PPA Price ($/MWh)	PPA Term (Years)	Asset Sale Price ($/kW)	ITC Assumption	Fixed O&M (2024 $/kW-yr)[2]
Solar PPA 1	425	2028	$68.75	20	*N/A*	*N/A*	*N/A*
Solar PPA 2	325	2027	$69.42	20	*N/A*	*N/A*	*N/A*
Solar PPA 3	201	2028	***Redacted – single bid***	15	*N/A*	*N/A*	*N/A*
Solar PPA 4	200	2028	$75.45	25	*N/A*	*N/A*	*N/A*
Solar Sale 1	130	2027	*N/A*	*N/A*	$2,096	40%	$23
Solar Sale 2	200	2029	*N/A*	*N/A*	$2,350	40%	$23
DER Solar PPA 1	10	2028	***Redacted – single bid***	20	*N/A*	*N/A*	*N/A*

Notes:
Each tranche listed represents a group of mutually exclusive projects, and certain cost data has been redacted, since it was developed from single RFP bids.
1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.
2: Baseline assumptions from NREL ATB used for tranche modeling purposes.

Figure 4-10: Summary of Solar+Storage Hybrid RFP Tranches

	Installed Solar Capacity (MW)	Installed Storage Capacity (MW)	Storage Duration (Hours)	In-Service Year[1]	PPA Price ($/MWh)	PPA Price ($/kW-yr)	PPA Term (Years)[2]	Asset Sale Price ($/kW)[3]	ITC Assumption	Fixed O&M (2024 $ /kW-yr)[4]
Hybrid PPA 1	453	250	4	2028	$64.33	$10.94	20	*N/A*	*N/A*	*N/A*
Hybrid PPA 2	300	225	4	2027	$64.96	$11.26	20	*N/A*	*N/A*	*N/A*
Hybrid PPA 3	250	125	4	2028	$72.58	$13.13	20	*N/A*	*N/A*	*N/A*
Hybrid PPA 4	200	100	4	2027	$81.49	$12.05	25	*N/A*	*N/A*	*N/A*
Hybrid Sale 1	164	164	4	2027	*N/A*	*N/A*	*N/A*	$1,944	40%	$35
Hybrid Sale 2	300	125	4	2028	*N/A*	*N/A*	*N/A*	$2,007	40%	$30
Hybrid Sale 3	343	171	4	2028	*N/A*	*N/A*	*N/A*	$2,538	40%	$31

Notes:
Each tranche listed represents a group of mutually exclusive projects, and certain cost data has been redacted, since it was developed from single RFP bids.
1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.
2: For modeling purposes, the shortest PPA term in the tranche was used even though the Hybrid PPA 2 and Hybrid PPA 3 tranches have bids varying between 20 and 25 years.
3: Note that asset sale price is based on the total installed capacity (solar + storage) of the tranche.
4: Assumptions from NREL ATB used for tranche modeling purposes, weighted by solar:storage ratio within the tranche.

Figure 4-11: Summary of Thermal and ZRC RFP Tranches

	Installed Capacity (MW)	In-Service Year[1]	Comments	PPA Term (Years)
Thermal PPA 1	600	2028	New Gas CC	20
Thermal PPA 2-4	150	2026	Various contractual options (heat rate call or blocks)	5
Thermal PPA 5	150	2027	Coal-based energy and capacity	2
Thermal Sale 1	18	2027	Existing gas peaker	*N/A*
ZRC 1-4	200	2025/26 – 2029/30	PJM external resource delivered to MISO border	Multiple options
ZRC 5-7	600	2025/26 – 2026/27	LRZ 4 delivery	Multiple options

Notes:
Each tranche listed represents a group of mutually exclusive projects. Cost data is not provided, given the fact that these tranches align to individual bids.
1: In-service year may be in the middle of the reported year.

4.6.3 Longer-Term New Resource Assumptions – Mature Technologies

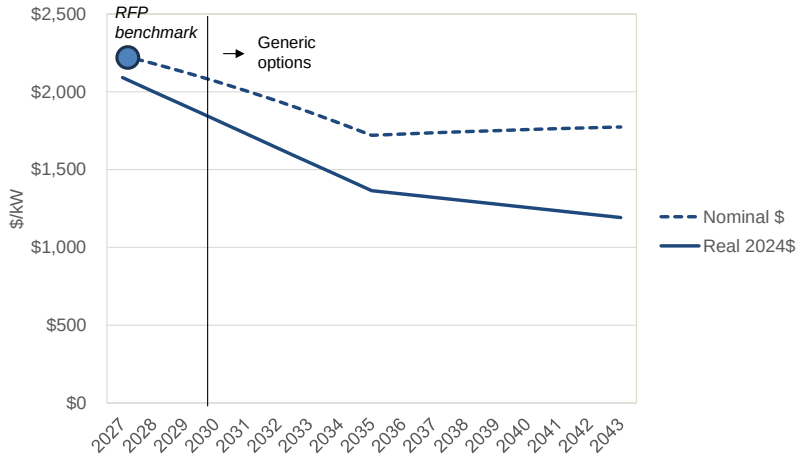
Beyond the RFP period, NIPSCO used a combination of RFP data, recent project experience, and third-party sources to develop cost and operational assumptions for well-

established technologies like solar, short-duration storage, wind, and natural gas-fired peaking and combined cycle technologies.

4.6.3.1 Solar, Wind, and Four-Hour Lithium-Ion Storage

For solar, wind, and four-hour lithium-ion storage resource assumptions over the long term, NIPSCO benchmarked cost data to RFP results or recent project experience[65] and applied technology learning curves using the "moderate" decline rate from NREL's Annual Technology Baseline report. The capital cost projections and assumed fixed operations and maintenance costs for these three technologies are summarized in Figure 4-12, Figure 4-13, and Figure 4-14.

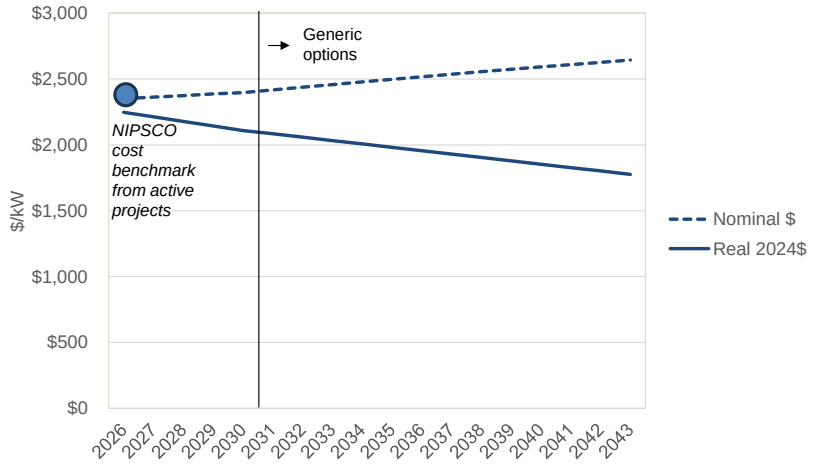
Figure 4-12: Long-Term Solar Cost Assumptions



Category	Assumption
Fixed O&M (2024$/kW-yr)*	$22
Capacity Factor	25%
Tax Credit Eligibility Assumption	40% ITC

**NREL ATB assumptions for 2027 benchmark year*

Figure 4-13: Long-Term Wind Cost Assumptions

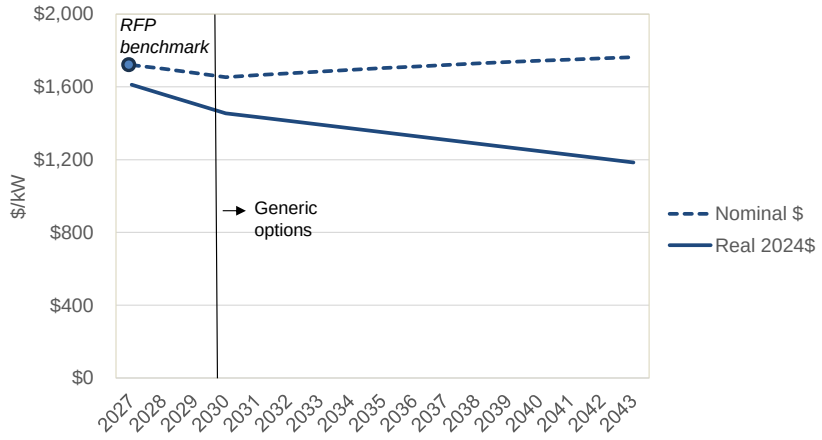


Category	Assumption
Fixed O&M (2024$/kW-yr)*	$34
Capacity Factor	39%
Tax Credit Eligibility Assumption	PTC

**NREL ATB assumptions for 2026 benchmark year*

[65] Note that no wind resources offered into the RFP, so NIPSCO's cost benchmarking data relied upon information from NIPSCO projects currently under development.

Figure 4-14: Long-Term Four-Hour Lithium-Ion Storage Cost Assumptions



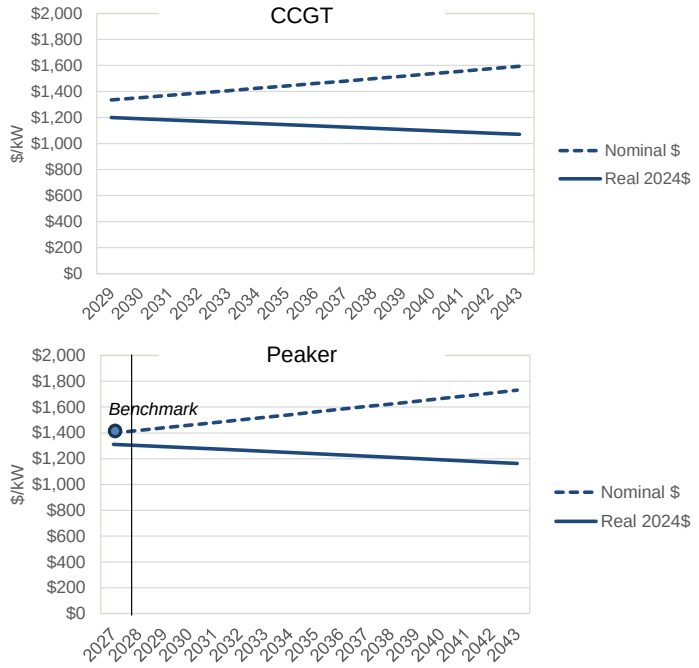
Category	Assumption
Fixed O&M (2024$/kW-yr)*	$40
Round Trip Efficiency	85%
Tax Credit Eligibility Assumption	40% ITC

**NREL ATB assumptions for 2027 benchmark year*

4.6.3.2 Natural Peaking and Combined Cycle

For new natural gas resource options, NIPSCO relied on internal engineering analysis and recent cost benchmarks for its recently proposed natural gas peaking project and applied technology learning curves using the "moderate" decline rate from NREL's Annual Technology Baseline report. In 2024 dollars, a new peaking resource was estimated at $1,284/kW based on NIPSCO's ongoing actual project experience. For new CCGTs, NIPSCO built the total "inside the fence" costs based on a high-level estimate provided by an external engineering consulting firm, based on 2 x 1 configurations in increments of 650 MW or 1,300 MW. Then for other costs, including electric interconnection, gas interconnections, water interconnection, owner's cost, and project contingency, NIPSCO escalated costs from an earlier IRP study at the historical inflation rate and projected inflation rate assumptions. This led to a total a total cost of $1,225/kW in 2024 dollars. The capital cost projections and assumed fixed operations and maintenance costs are summarized in Figure 4-15.

Figure 4-15: Long-Term Natural Gas Resource Option Cost Assumptions



Category	Peaker	CCGT
Fixed O&M (2024$/kW-yr)*	$24	$37
First Available Year	2028	2029

**NREL ATB assumptions for appropriate benchmark years*

4.6.4 Emerging Technologies – Hydrogen

The 2024 IRP incorporates the potential for significant system load growth, and NIPSCO recognizes that new, emerging technologies will be needed to achieve emission reduction levels that aim toward a net zero target. One such technology is the use of hydrogen as an alternative fuel to natural gas. The concept of using hydrogen as a source of clean fuel or as a long-duration storage solution has been present in the energy industry for some time. When burned for fuel or consumed in a fuel cell, pure hydrogen emits zero greenhouse gas emissions. In addition, once produced, hydrogen may be stored in existing natural gas infrastructure until it is ready to be burned for fuel in a gas turbine, distributed for residential and commercial heating, or sold to an industrial customer. Due to these characteristics, hydrogen has the potential to be a dispatchable, versatile, zero-emitting alternative to fossil fuels or intermittent resources.

Many obstacles exist to achieving cost-effective, widespread production and consumption of hydrogen in the near term (including cost, lack of availability of transportation and distribution infrastructure, and regulatory uncertainty). However, emerging investment across the energy value chain, federal encouragement, and significant tax credit opportunities may make the technology viable over the mid- to long term.

For the 2024 IRP, NIPSCO considered hydrogen as a possible resource option and developed cost inputs based largely on independent research and analysis. The remainder of this section provides additional context around hydrogen production and a discussion of NIPSCO's key input assumptions.

4.6.4.1 Hydrogen Production Technology

Hydrogen has the potential to store and deliver zero-emitting energy. However, hydrogen does not typically exist in an isolated form in nature and must be produced from compounds containing it. Today, hydrogen is most commonly produced from thermal processes such as SMR of natural gas, producing what is referred to as "grey" hydrogen (or "blue" hydrogen, if a carbon capture and storage facility is further used to capture and store the carbon emissions from the SMR process). In addition, as electrolyzer and renewable prices become more competitive, and as federal tax credits offer significant subsidies for the production of clean hydrogen, the use of renewable energy to power the process of water electrolysis to produce "green" hydrogen may also become viable. Green hydrogen is made by using zero-emissions electricity to power an electrolyzer, which splits water into hydrogen and oxygen through the electrolysis process while producing no greenhouse gas emissions.

Green hydrogen is currently more expensive than grey or blue hydrogen, primarily due to low economies of scale, and it is not produced commercially. However, the hydrogen tax credit, expectations for significant improvements in system cost components, continued market evolution toward increased renewable penetration, technology advancement associated with carbon capture and storage, and potential future carbon regulation may make green and blue hydrogen production more attractive in the long term.

4.6.4.2 Hydrogen Production Constructs

While clean hydrogen is not currently produced at a commercial scale, a "hydrogen economy" could one day develop in one of many forms, each of which would suggest a different modeling approach within a utility resource plan. While these frameworks are speculative, they are useful in helping to define a quantitative approach for analyzing the long-term viability of green hydrogen for the 2024 IRP. NIPSCO considered several hypothetical hydrogen deployment models, as summarized in Figure 4-16.

Figure 4-16: Possible Hydrogen Production Configurations

<table>
<tr><th>Business Model</th><th>Electrolyzer Ownership</th><th>Electricity Ownership</th><th>Gas Plant Ownership</th></tr>
<tr><td rowspan="3">“Islanded”
NIPSCO Ownership Model</td><td rowspan="3">NIPSCO
Capex + fixed costs for electrolyzer, water, storage</td><td>NIPSCO
Capex + fixed costs or PPA for renewable electricity</td><td rowspan="4">NIPSCO
Gas plant retrofit costs</td></tr>
<tr><td>NIPSCO + Market</td></tr>
<tr><td>Market
Grid electricity prices</td></tr>
<tr><td>“Economy”
Purchase H2 for a NIPSCO-owned H2-enabled gas plant</td><td>Third Party
Modeled as a PPA cost for green H2 (inclusive of all production costs)</td><td>Third Party</td></tr>
</table>

The “islanded” model assumes the utility owns or contracts with all components of the hydrogen production process, including the electrolyzer and electricity sources to produce hydrogen, then consumes the produced hydrogen at its own hydrogen-enabled gas plants to produce electricity during optimal hours. The hydrogen production cost from the “islanded” approach would include the amortized fixed costs to install and operate the electrolyzer, hydrogen storage facilities, and specific renewable projects used to power the electrolysis process, as well as the variable costs for any grid-sourced electricity and water. Additional costs to transport the hydrogen to the gas plant and to retrofit and operate the plant would also be separate, post-production costs to the utility.

Alternatively, if a functional hydrogen economy is assumed to develop over time, one could extend the “islanded” approach to assume that the utility producer of hydrogen can also optimally sell hydrogen to customers in a broader hydrogen market. For modeling purposes, one could easily imagine the opposite situation, in which the utility simply purchases hydrogen from the market or contracts with third-party green hydrogen producers at a negotiated commodity price to fuel a gas plant. This approach assumes that a suitable transmission and distribution infrastructure builds out over the long term in the hydrogen economy and aims to capture the economics within the assumed hydrogen market as a whole, rather than just the utility-specific power generation assets that would “feed” the electrolyzer. The assumed market commodity price of hydrogen would be an all-in cost, including the fixed and variable costs of production. NIPSCO used the latter framework as the basis for its long-term economic analysis.

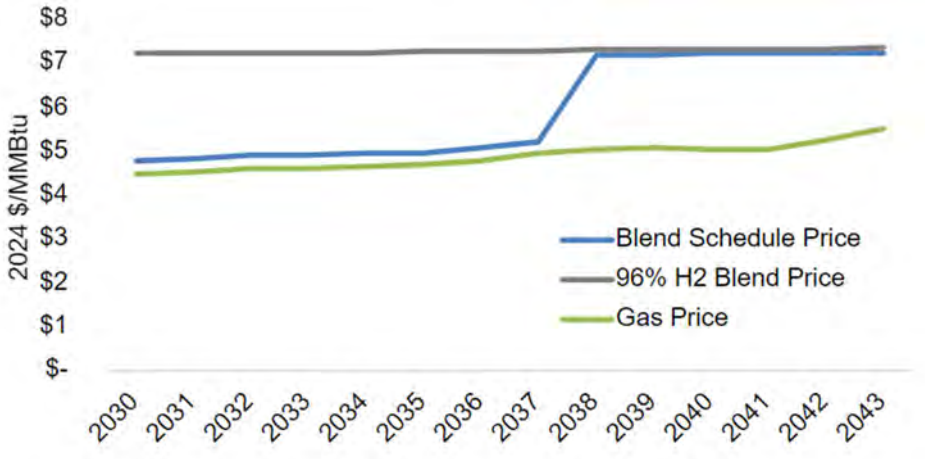
4.6.4.3 Hydrogen Modeling Input Assumptions Development

For modelling of hydrogen, NIPSCO assumed an all-in hydrogen cost of $30/MMBtu or approximately $4/kg in real 2024$ throughout the 2024 IRP's study period. The price assumption was based on a number of public sources, most notably Lazard's Levelized Cost of Hydrogen buildup[66] and The International Energy Agency's Hydrogen pricing map by region.[67]

For modeling purposes, NIPSCO anticipates the availability of green hydrogen in 2030 and beyond, allowing for Hydrogen Production Tax Credits (see Section 4.6.10 for additional detail on the Section 45V tax credits) to be earned. The green hydrogen credit of $3/kg is approximately worth $22.5/MMBtu, which translates to a net hydrogen price of $7.25-$7.5/MMBtu in real 2024$.

For modeling purposes, NIPSCO has assumed a 96% hydrogen blend by volume for new hydrogen-enabled resources and a potential blend schedule of 30% by volume until 2038 for NIPSCO's existing Sugar Creek facility. The resulting fuel prices per MMBtu for these two hydrogen blends and natural gas under the Reference Case are summarized in Figure 4-17.

Figure 4-17: Annual Hydrogen Fuel Price Assumptions



4.6.4.4 Hydrogen Blending in Gas Turbines

To consume hydrogen fuel in natural gas turbines, certain modifications need to be made to the turbines themselves, as well as other infrastructure such as pipelines and emission controls. The magnitude of the cost impact is dependent on the amount of hydrogen being consumed in the facility relative to the amount of natural gas (i.e., the blending percentage). While only relatively low hydrogen blends (5% to 20%) have been used in gas turbine technologies today, a plant can be upgraded to accommodate higher hydrogen blend concentrations as emissions restrictions

[66] Lazard, "Lazard's Levelized Cost of Hydrogen Analysis", 2021. https://www.lazard.com/media/12qcxl1j/lazards-levelized-cost-of-hydrogen-analysis-vf.pdf

[67] International Energy Agency, "Levelized Cost of Hydrogen Maps", 2023. https://www.iea.org/data-and-statistics/data-tools/levelised-cost-of-hydrogen-maps

become more stringent and/or as the hydrogen industry expands. Key operational considerations include:

- Combustor configuration
- Safety and flammability controls
- NO_x controls
- Pipeline upgrades
- On-site hydrogen storage
- Maintenance changes

For purposes of the IRP modeling, NIPSCO used bidder data from past RFPs and information gathered from Original Equipment Manufacturers to project the costs required to achieve very high levels of blending (including up to 96% hydrogen by volume) over the long term. Thermal plants retrofitted or built to accommodate pure or close to 100% hydrogen were assumed to require approximately 30% of the original plant capex and operating costs, or about $400/kW in real 2024$.

4.6.4.5 Regional Hydrogen Projects

As a part of the U.S. Department of Energy's Hydrogen Hub Initiative, which is allocating $8 billion in federal funding to establish regional hydrogen hubs in the U.S., NIPSCO will likely be poised to access green and blue hydrogen supply from the MachH2 Hydrogen Hub located across Midwest states and including NIPSCOs service territory. The MachH2 hub has been awarded up to $1 billion in funding from the DOE for hydrogen projects and incorporates over 70 partners across various industries, with the expectation of creating 13,600 direct jobs.[68]

The MachH2 hub plans to incorporate at least two primary hydrogen production projects that will supply offtake to Indiana and Illinois. The first is located at BP's Whiting Refinery and plans to produce at least 200,000 tons per year of blue hydrogen beginning in 2031, with increases in production volume in later years.[69] BP has announced an investment of at least $4 billion into the project, which will begin construction in 2025.[70] Although a significant portion of this hydrogen will likely serve as captive supply for BP's refinery, it also poses a significant low-carbon hydrogen offtake opportunity for NIPSCO.

In addition to the BP Whiting Refinery, Constellation Energy has announced a low-carbon hydrogen project at its La Salle nuclear facility in Marseilles, Illinois that is also part of the MachH2 hydrogen hub. This project will produce an estimated 33,450 tons of hydrogen per year[71] for supply to the region and would be the largest nuclear-powered clean hydrogen facility upon completion in the early 2030s.

---

68 Argonne National Laboratory, 2023.

69 Reuters, 2022

70 Northwest Indiana Times, 2024

71 Power Magazine - "Constellation Planning Significant Nuclear-Powered Hydrogen Facility at LaSalle"

4.6.5 Emerging Technologies – Renewable Natural Gas

Another potential emerging technology that could be deployed in NIPSCO's existing or future natural gas-fired power plants is RNG. RNG can be burned directly in the combustion chamber of gas turbines as a replacement for conventional natural gas. Since RNG is derived from organic waste and has the potential to be carbon-negative, its use in combined cycle gas turbines can significantly reduce greenhouse gas emissions from power generation.

Several primary production methods of RNG exist, including: (1) anaerobic digestion, which breaks down organic matter (agricultural waste, food waste, or manure) in the absence of oxygen to produce biogas as a feedstock for RNG; (2) landfill gas recovery, or the capturing of methane produced from decomposing organic waste in landfills; (3) gasification, which converts biomass into syngas through high-temperature processes, which can then be converted to RNG; and (4) pyrolysis, or the decomposition of organic material at high temperatures in the absence of oxygen. Currently, landfill recovery gas is often one of the more cost-effective methods due to its reliance on existing infrastructure rather than additional capital investment. A number of RNG production projects currently exist in Indiana, with Amp Americas operating the largest dairy RNG production facility in the U.S. in Jasper County.[72] Further, Kinder Morgan operates three RNG facilities in Wyatt and Monticello, Indiana,[73] which may be leveraged for offtake and use as a decarbonization fuel.

4.6.6 Emerging Technologies – Carbon Capture, Utilization, and Storage

Another emerging technology that may be positioned to support the decarbonization of the electricity sector is CCUS. Broadly, this technology refers to processes that (i) capture and separate CO2 directly from a fossil fuel (such as from coal in an IGCC process) or the flue gas of an electric power plant post-combustion or other point-source emission stream of CO2; (ii) purify, compress, and transport the CO2; and (iii) utilize (such as in an EOR process) or sequester the CO2 underground in saline reservoirs or unused coal seams.

NIPSCO's RFP did not generate any bids related to CCUS. However, the MISO market scenario analysis incorporated CCUS technology as a plausible generation resource option under scenarios with significant carbon reduction trajectories (*see* Section 8), and it remains a potentially feasible option for NIPSCO for new or existing natural gas capacity. The remainder of this section provides an overview of the technology, potential cost ranges, and federal policy support considerations.

72 DMT Clear Gas Solution

73 Kinder Morgan

4.6.6.1 CCUS Technology Overview

The CCUS value chain comprises three segments: capture, transport, and end-use, which includes both storage and utilization.

Capture

Point-source capture methods include post-combustion, pre-combustion, and oxy-combustion. These technologies are used across various industries such as ammonia production, coal and natural gas power generation, cement manufacturing, chemical and refining processes, ethanol production, hydrogen production, iron and steel manufacturing, natural gas processing, and pulp and paper production.

Post-combustion capture extracts CO2 from flue gas, syngas, or process streams after fuel combustion. In this process, chemical solvents (typically amines) absorb CO2 from the flue gas. The CO2-rich solution is then heated in a stripping column to release the CO2, which is compressed for transport and storage, while the solvent is reused.[74] These systems can be deployed at large scales and are well-suited for retrofitting existing facilities.

Pre-combustion methods, including gasification and pyrolysis, provide alternative CO2 capture approaches. In gasification, the fuel undergoes controlled partial oxidation in a gasifier, generating syngas consisting of H2, CO, and trace gases. A subsequent step in a water-gas-shift reactor converts CO to CO2 and enhances the concentrations of H2 and CO2 in the gas stream. Due to the high partial pressure of CO2 in syngas compared to flue gas, it becomes feasible to separate CO2 using various technologies, yielding nearly pure hydrogen fuel. Similarly, pyrolysis heats methane in the absence of oxygen until it separates into solid carbon and hydrogen gas. Although less technologically developed, pre-combustion methods may prove to be more commercially cost-effective relative to post-combustion approaches, as they require treatment of a smaller gas volume to achieve equivalent carbon capture quantities.

In the oxy-combustion approach, coal is burned in an enriched oxygen environment rather than air, which results in combustion products of CO2 and water.[75] The water can be condensed, leaving the CO2 ready for capture. Oxy-combustion lowers NOx and mercury emissions relative to conventional combustion, but its requirement of high-purity oxygen increases operational costs.

Transport

Once CO2 is captured, the next step is compression and transportation to suitable end-use sites. In the U.S., a relatively small network of around 5,000 miles of CO2 pipelines already exists in certain regions, developed primarily for other industries such as EOR.

While other transportation methods such as rail, truck, and ship are available, they generally prove to be significantly more expensive and are typically reserved for specific applications where pipeline transport is not feasible. Expanding the current pipeline network will

74 NETL – "Carbon Dioxide Capture Approaches"

75 Ibid

be a critical enabler for the scaling of CCUS, although permitting, environmental concerns, and community opposition pose significant threats as well.

End-Use

After transportation, captured carbon can either be stored or utilized. Storage methods for captured CO2 include saline aquifers, depleted oil and gas reservoirs, EOR reservoirs, and mineralization in geological structures. For NIPSCO in particular, the saline aquifer geological features around NIPSCO's natural gas-fired Sugar Creek combined cycle plant may be appropriate for CCUS siting.[76]

With estimated storage capacities ranging from 2,400 to 21,000 billion tons, these methods can accommodate captured CO2 for hundreds to thousands of years. In the U.S., the DOE's CarbonSAFE initiative has been pivotal in advancing site development for CO2 storage. Currently, ten sites with at least 50 million tons of storage have undergone feasibility or characterization studies in addition to 300 million tons across 11 sites identified by other developers.

CO2 utilization involves converting captured carbon into commercial products, reducing emissions while creating value-added materials. Although currently smaller in scale compared to storage, demand for CO2 utilization is anticipated to grow substantially over the next 30 years. North America's demand is projected to reach approximately 40 MTPA by 2030 and 100 to 250 MTPA by 2050.[77] One utilization case for CO2 is in building materials, where it can be used in the production of cement or aggregates. In the plastics and chemicals industries, CO2-derived PEC and PPC are used to make polyurethane plastics. Additionally, CO2 can be converted into syngas via co-electrolysis for fuel synthesis.

4.6.6.2 Current Operational Landscape

As of the end of 2023, the Global CCS Institute recorded a dynamic global landscape with 41 operating CCS projects and an additional 351 projects in various stages of development.[78] This includes 11 new facilities in operation and 15 projects starting construction within the year. Collective global capture capacity across projects from operational to early development stages is approximately 361 MTPA of CO2.

In the U.S. and Canada, CCUS is gaining momentum across various industries. Currently, the ethanol sector supports the most CCUS facilities, followed closely by CO2 transport and storage infrastructure.[79] There are 21 operational CCUS facilities in the region, with nine under

---

[76] See the DOE's *Carbon Storage Atlas:* https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf and Great Plains Institute's report titled, "Transport Infrastructure for Carbon Capture and Storage, Whitepaper on Regional Infrastructure for Midcentury Decarbonization. https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf. In addition, Wabash Valley Resources' proposed CCUS project is in close proximity. For more information, see: https://www.wvresc.com/

[77] DOE – "Pathways to Commercial Liftoff: Carbon Management"

[78] Global CCS Institute – "Global Status of CCS 2023"

[79] Ibid

construction, 80 in advanced development stages, and 92 in early development phases.[80] Current CCUS capacity in the U.S. exceeds 20 MTPA, although modeling indicates that achieving U.S. energy transition goals will necessitate the annual capture and storage of 400 to 1,800 MT of CO2 by 2050.[81]

4.6.6.3 Demonstration Projects

Carbon capture technologies vary in TRLs from 3 to 9. Established pre- and post-combustion methods are commercially available, with TRLs of 8 to 9, while oxy-fuel capture is at TRL 7. Storage technologies such as enhanced oil recovery and saline aquifers are also at TRLs of 8 to 9, indicating commercial readiness. Some current projects aim to convince the market of the viability of established technologies, while others are testing new carbon management configurations.[82] The following examples illustrate CCUS projects in both operational and developmental stages.

The $1 billion Petra Nova project, located at the 240 MW W.A. Parish Generating Station in Thompsons, Texas, captures CO2 using an amine-based solvent and transports it via pipeline to an enhanced oil recovery site near Houston. After operating from 2017 to 2020, the project was halted due to low oil prices but resumed operations in September 2023.[83] Capturing 90% of the plant's carbon emissions and possessing 1.4 MTPA of sequestration capacity, it is a prime example of large-scale commercial CCUS.

The Air Products and Chemicals Louisiana Clean Energy Complex, currently under construction, aims to produce over 750 million standard cubic feet of blue hydrogen daily and sequester more than five MTPA of CO2, with operations slated to begin in 2026. This project, which incorporates a CCUS unit at a natural gas gasification plant, highlights the critical role of existing infrastructure in determining project feasibility given its proximity to existing hydrogen pipelines.[84] However, it faces significant local opposition due to concerns about carbon storage under Lake Maurepas, a site used for fishing and recreation. Fears of potential construction impacts and leakage have sparked community efforts to halt the project, emphasizing the need for early and effective community engagement in new developments.

Clean Energy Systems is developing the Mendota BECCS facility, which is designed to capture 0.3 MTPA of CO2 while generating electricity for the grid.[85] Set to commence commercial operations in 2025, the facility will generate significant community benefits, including enhanced air quality from utilizing 200,000 tons of local agricultural waste and an increase in tax revenue.

---

80 DOE – "Pathways to Commercial Liftoff: Carbon Management"

81 Ibid

82 Global CCS Institute – "Global Status of CCS 2023"

83 Power Engineering – "Groundbreaking Petra Nova CCS project back up and running, owner says"

84 Air Products – "Louisiana Clean Energy Complex"

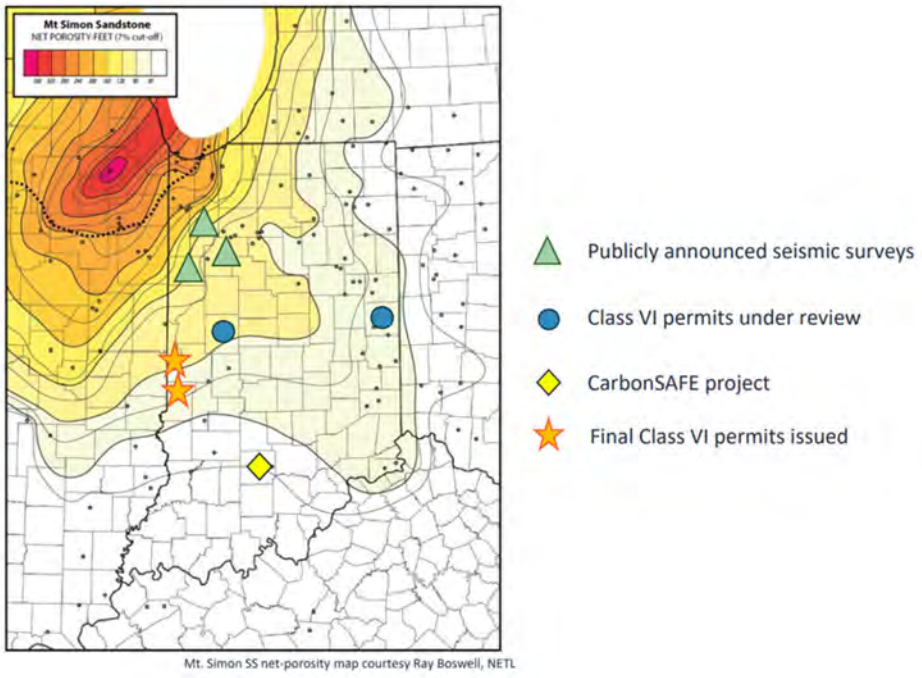
85 Clean Energy Systems – "Mendota Biomass Carbon Removal and Storage Project (BiCRS)"

This project exemplifies ongoing progress in unlocking the significant environmental benefits afforded by CDR technologies.

4.6.6.4 Local CCUS Feasibility

In addition to the previously described demonstration projects, several local CCUS projects are in advanced stages of development local to NIPSCO's service territory. The Wabash CarbonSAFE project was one of only six projects awarded for Phase II work by the US Department of Energy and will establish the feasibility of developing a carbon storage complex near Mitchell, Indiana, and may be operational as early as 2029. The project takes advantage of the Indiana region's favorable geological storage capacity for carbon dioxide, which is among the most significant in the continental United States.[86] In addition to the CarbonSAFE project, Wabash Carbon Services has been advancing several CCUS projects in proximity to NIPSCO's Sugar Creek facility in Vigo County, Indiana. The EPA issued final Class VI permits on these wells, which began construction in January 2024 and are anticipated to be able to sequester 1.67 million metric tons of carbon dioxide per year per well by 2034 to 2036.[87] Several other CCUS projects near or inside of NIPSCO's service territory remain in earlier stages of development, as summarized in Figure 4-18.[88]

Figure 4-18: Current CCUS Project Activity within Regional Mt. Simon Sandstone



86 Princeton University, Net-Zero America, 2021

87 EPA.gov

88 Indiana Geological and Water Survey

4.6.6.5 Federal Tax Incentives and Other Federal Policy

The U.S. tax code offers a performance-based tax credit for eligible carbon capture and sequestration projects that securely store CO2 in geological formations or use CO2 for enhanced oil recovery. These incentives, known as the 45Q credits, were increased and extended by the Inflation Reduction Act to $85 per ton for geological storage. The tax credit is applied to all tons sequestered, is available for 12 years following project operation, and grows with inflation after 2026. Additionally, the BIL and the CHIPS Act support CCUS through substantial funding. The BIL allocates $12 billion for carbon capture research and demonstration until 2026, $8.5 billion for new capture and storage facilities, and $3.6 billion for direct air capture. The CHIPS Act supports carbon storage research and geologic computational science through the DOE.

4.6.6.6 CCUS Cost Estimates

Since the 2024 RFP did not yield any CCUS projects, NIPSCO-specific portfolio analysis of the technology was not performed. However, in order to develop perspective on long-run CCUS costs to be used in the MISO market scenario analysis (*see* Section 8) and to approximate the potential cost and operational impacts of a CCUS retrofit to the existing Sugar Creek combined cycle, CRA and NIPSCO performed a review of third-party estimates. Overall, costs for CCUS projects fall within the following three categories, as described in more detail above:

- Capturing CO2 at the source of emission and compressing or liquifying it for transport;[89]
- Transporting the CO2 via pipeline, ship, or truck, as appropriate; and
- Sequestering the CO2 underground, including costs associated with injection, monitoring, and verification.

CRA developed CCUS costs and operational parameters for both retrofit of NIPSCO's existing Sugar Creek natural gas combined cycle unit and a new natural gas CCUS facility based on a range of public sources, including NREL and EPA.[90] Figure 4-19 summarizes CCUS cost and operational parameter assumptions for both Sugar Creek and a new CC with CCUS, while Figure 4-20 provides assumptions for new CC with CCUS capital costs over the full planning horizon based on NREL cost curves.

[89] Capital expenditures are largely associated with an absorption tower, energy consumption requirements that are often represented through reductions in power output of the host facility, and compression costs.

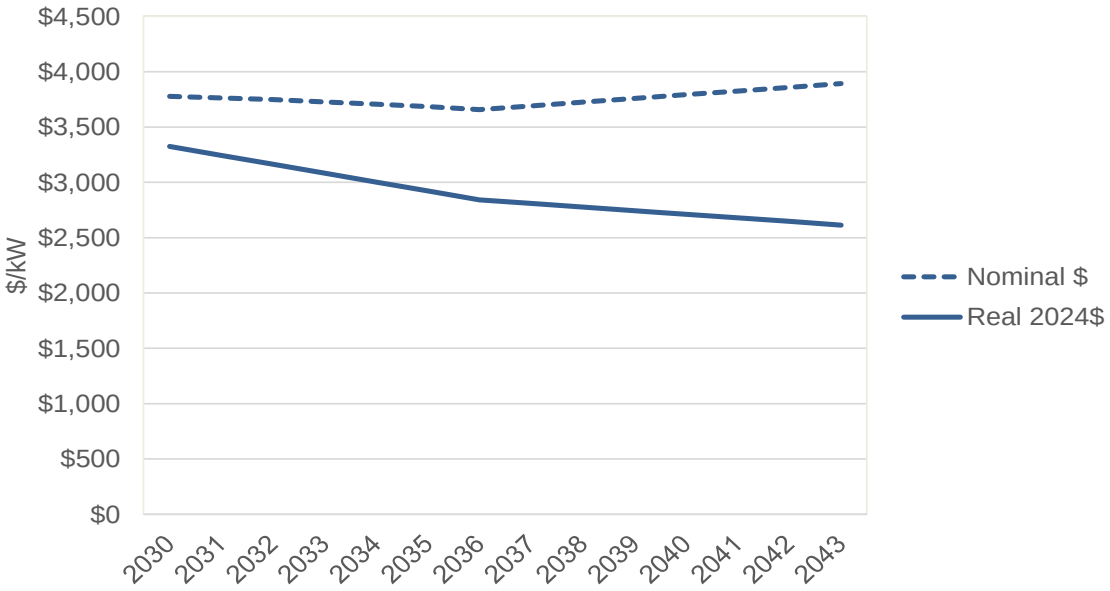
[90] See 2023 NREL Annual Technology Baseline and U.S. Environmental Protection Agency CO2 Capture, Storage, and Transport Assumptions: Chapter 6 - CO2 Capture, Storage, and Transport (epa.gov)

Figure 4-19: CCUS Costs and Operational Parameters

Characteristic	Units	Sugar Creek Before Retrofit	Sugar Creek After Retrofit	New CC with CCUS
Net Capacity to Grid (Winter)	ICAP MW	650	585	585
Net Capacity to Grid (Summer)	ICAP MW	650	585	585
Heat Rate (Winter)	Btu/kWh	6,903	7,662[1]	6,704
Heat Rate (Summer)	Btu/kWh	6,912	7,672[1]	6,704
Installed CapEx	2024$/kW	-	1,860	3,325
VOM Costs	2024$/MWh	1.32	3.34[2]	4.64
Fixed Operations and Maintenance Costs	2024$/kW-yr	23.33	46.99[3]	82.02
CO2 Transportation Cost[5]	2022$/ton	7.50	7.50	7.50
CO2 Sequestration Cost[6]	2022$/ton	4.86	4.86	4.86
CO2 Emission Rate	lbs/MMBtu	119	11.9[4]	11.9[4]

Notes:
1: Assumes an increase in heat rate by a factor of 1.11x.
2: Assumes a 2.29x increase in VOM.
3: Assumes a 1.96x increase in FOM.
4: Assumes 90% carbon capture.
5: See https://www.epa.gov/system/files/documents/2024-04/table-6-5-co2-transportation-matrix-in-epa-2023-reference-case.xlsx
6: See https://www.epa.gov/system/files/documents/2024-04/table-6-4-co2-storage-cost-curves-in-epa-2023-reference-case.xlsx

Figure 4-20: Long-Term CCUS Cost Assumptions



4.6.7 Emerging Technologies – Long-Duration Energy Storage

Although a large majority of storage bidders in the RFP offered four-hour duration lithium-ion battery storage technologies, three bids incorporated longer duration technologies (see Section 4.6.1.2 above), and longer-duration storage technologies may become more viable over the long-

term in order to balance diurnal variations in renewable energy resources as well as variations in demand from weekends (low demand) to weekdays (high demand). The technology can also provide needed capacity during longer duration weather events, such as snowstorms, extended cloud cover, or wind droughts that could last for several days.

The value of long-duration storage is likely to increase as intermittent renewable generation increases within the MISO footprint. In addition to energy arbitrage, some long-duration technologies may also be able to effectively offer additional ancillary services value, such as spinning reserve and regulation to the portfolio.

In general, short duration is defined as any technology with less than 10 hours of storage duration; inter-day LDES assets can shift power by 10-36 hours, filling diurnal needs by allowing excess power to be used within the same or following day; multi-day/week LDES shifts power by 36-160+ hours, enabling power supply during extended shortfalls; and seasonal duration storage provides several weeks to several months of storage, helping to address seasonal demand fluctuation. Long-duration storage technology can take many forms, as described in the next section of this Section.

4.6.7.1 Thermal Energy Storage

(TES stores high or low temperatures for hours, days, weeks, or seasons. Potential advantages include inexpensive materials, low environmental impact, versatility to release either electrical or thermal energy, ability for large scale storage, and superior safety.[91] However, this technology has limited applications at power generation facilities relative to other storage types as it often has lower RTE, lower energy density, a larger footprint, and limited scalability. Contributing to its inefficiencies are technology-specific operational requirements like passive heating during downtime.[92] Sensible heat, latent heat, and thermochemical heat constitute the three types of TES, each with tradeoffs of their own.

SHS involves raising the temperature of a solid or liquid medium to store heat.[93] This method provides wide duration flexibility from minutes to months and is currently the most commercially available among TES technologies. In power generation, the most common forms of SHS include molten salt TES (used in concentrated solar power), concrete TES, and chilled water TES. These systems typically achieve lower RTEs ranging from 40% to 90% and have long lifetimes spanning 25 to 30 years.

LHS captures heat in phase change materials, offering medium-storage durations from hours to days. Implementations of the technology span from laboratory stage to commercial availability. LHS is characterized by high modularity and energy density, high RTEs of 75% to 90%, a 10 to 30 year lifetime, minimal geographic constraints, and constant discharge temperatures

91 LDES Technologies | LDES Council

92 NETL – "Thermal Energy Storage"

93 LDES Council – "Long Duration Energy Storage to accelerate energy system decarbonization"

over time. However, LHS uses corrosive, rare materials and is highly application specific, which exposes it to supply chain vulnerabilities.[94]

THS utilizes endothermic and exothermic chemical reactions to store thermal energy. It provides storage capabilities spanning hours to months and is predominantly in the R&D phase. It benefits from having minimal heat loss, a 10 to 30 year lifetime, very high RTEs of 80% to 99%, no geographic constraints, and the highest energy density among TES; however, it is limited by slow charging rates and materials that can degrade over time.[95]

4.6.7.2 Mechanical Energy Storage

MES harnesses kinetic or potential energy by exerting force to induce acceleration, compression, or displacement in a medium such that the energy can be later recovered. It is recognized for its potential to operate at large scales, long project lifetimes up to 30 years, high RTEs ranging from 70% to 90%, and rapid response.[96] However, this storage method can be constrained by geographic considerations, prolonged construction lead times, large physical footprints, high environmental impacts, and high initial capital costs. There are many different types of MES with varying levels of maturity and performance tradeoffs.

PHS utilizes surplus energy to pump water to an elevated reservoir, which can later be released through hydraulic turbines to generate electricity. Emerging pumped hydro systems strive to offer increased modularity and a smaller footprint compared to traditional installations, while still maintaining the high ramp rate and rapid response time of traditional designs. Like PHS, gravity-based storage stores the potential energy of large masses by raising them into an elevated position using excess energy and releasing them when energy is needed. Gravity-based systems offer high modularity, high RTE, quick response times, and inter-day storage durations, but they have seen limited commercial deployment to-date.

CAES involves using electricity to compress air, which can then be discharged on demand within a multi-day/week timeframe. It is highly modular, occupies a small footprint, and is cost-effective, although its geographic applicability is limited due to reliance on underground geological storage systems. LAES operates similarly to CAES but compresses air to the point of liquefaction, supporting storage durations from inter-day to multi-day/week. It provides enhanced modularity and occupies smaller footprints compared to CAES, although it comes with higher capital costs. Despite being the newest among mechanical storage technologies, LAES is anticipated to be competitive in terms of cost, response time, and modularity, while offering storage durations spanning multiple days to weeks.[97] Liquid CO2 storage functions like LAES but

94 DOE – “Pathways to Commercial Liftoff: Long Duration Energy Storage”

95 NETL – “Thermal Energy Storage”

96 The Electricity Journal – “Technology readiness level and round trip efficiency of large-scale advanced compressed air energy storage”

97 As described in Section 4.6.1.2, NIPSCO received a bid in its RFP for the Energy Dome liquid CO2 storage system, which utilizes an above-tank to achieve inter-day storage by compressing CO2. The heat generated during compression is captured using two TES systems: one for direct heat transfer and another employing a heat exchanger to cool the CO2 to a liquid phase for storage in a dome-shaped, above-ground pressure vessel. The discharge process reverses this cycle, reheating the stored CO2 so that it can be expanded through a turbine.

leverages the uncommon property of pure CO2 streams to be condensed and stored as a liquid under pressure at ambient temperatures.

Flywheels store energy by rotating a mass around a fixed axis. They are characterized by modularity, rapid construction times, immediate dispatchability, and low maintenance requirements, although they typically have short discharge durations and limited storage capacities.[98]

4.6.7.3 Chemical Energy Storage

CES is achieved through the production of chemical fuels. It can be converted into electrical, thermal, or mechanical energy, making it versatile for use in industrial or grid applications.[99] This storage method offers several advantages, including large storage capacities; discharge durations ranging from days to months; long project lifetimes; ease of storage and transport; minimal energy loss; and various pathways for production, storage, and end use. Chemical fuels can also leverage alternate revenue streams beyond electricity sales with the help of extensive existing infrastructure. However, CES may be constrained by geographical considerations, require large amounts of land, and present safety hazards. Some chemicals have low volumetric energy densities, which can result in further constraints by requiring large, expensive storage volumes. Compared to batteries, CES generally has lower RTEs due to the energy intensive process it requires.

The main types of chemical fuels are methane, methanol, ammonia, and hydrogen.[100] Hydrogen is typically a primary option for CES due its low-carbon production methods, diverse-end use applications, and ability to provide clean energy.[101] Methane benefits from a higher volumetric energy density than hydrogen and widespread infrastructural support but causes significant greenhouse gas emissions. Ammonia, which can be formed from hydrogen and nitrogen, has existing transportation infrastructure largely due to its use as a fertilizer and is currently being studied for use in power generation. Methanol, formed through the hydrogenation of CO and CO2, can be more easily stored and transported relative to other fuels but may be more suited for use in transportation than power generation due to its low energy density, emissions, and difficult integration into existing natural gas infrastructure.

4.6.7.4 Electrochemical Energy Storage

EES, often classified as a subset of chemical energy storage, involves the cyclic conversion of energy between electrical and chemical forms through electron and ion transfer in electrodes.[102] While still largely in early stages of development for LDES purposes, these systems can offer inter-day and multi-day/week storage durations and are known for their safety, minimal geographic

98 NETL – "Mechanical Energy Storage"

99 NETL – "Chemical Energy Storage"

100 Ibid

101 Hydrogen for power generation is described in more detail in Section 1.6.5.1.

102 ScienceDirect – "Introduction to electrochemical energy storage technologies"

constraints, resilience to extreme temperatures, scalability, low self-discharge rates, ability to discharge deeply without significant degradation, and long operational lifespans. Common drawbacks of EES include safety hazards, high costs, temperature sensitivity, degradation over time, and reliance on rare minerals.

Lithium-ion batteries are currently at the forefront of electrochemical energy storage solutions, commonly featured in integrated resource planning due to their proven commercial viability and technological readiness. Although they are technically a short-duration storage option, lithium-ion batteries benefit from low capital costs, fast response rates, short construction times, high RTEs of 85% to 95%, discharge times from 1 second to 8 hours, and high energy density.

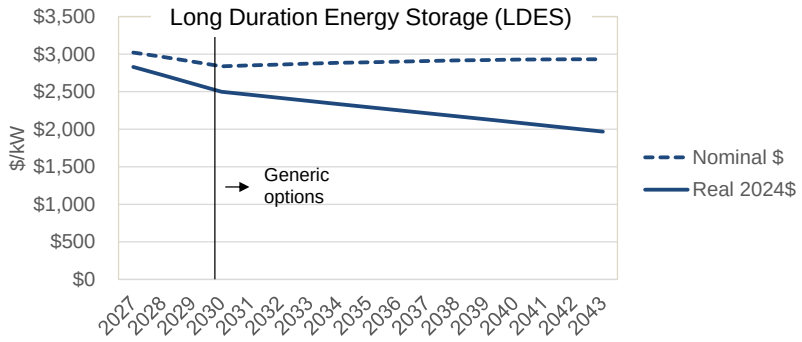
A few promising long duration technology categories identified by the U.S. Department of Energy include aqueous-electrolyte flow batteries, metal-anode batteries, and hybrid flow batteries. While this list is far from comprehensive, it helps to demonstrate some of the key characteristics of electrochemical LDES technologies. Aqueous-electrolyte flow batteries, like vanadium redox flow batteries and iron-chromium flow batteries, employ chemical cathodes and anodes separated by electrolytes. They are characterized by near instantaneous response times, long cycle lives, modular designs, RTEs between 65% to 85%, small footprints, and inter-day to multi-day/week durations, although they are subject to a form of relatively fast degradation known as crossover and can be expensive.[103] Hybrid flow batteries, which maintain tradeoffs similar to those of aqueous-electrolyte flow batteries, can offer enhanced performance by combining the strengths of conventional and flow battery chemistries. Metal-anode batteries are technologically similar to lithium-ion batteries, and have large specific and volumetric capacity, high energy density, quick response times, and small footprints. Finally, as described in more detail in Section 4.6.1.2, NIPSCO received a bid for iron air storage, which falls within this category.

4.6.7.5 LDES Cost Considerations

Since LDES encompasses a diverse range of technologies, costs have the potential to vary widely, although declines are likely in the future. This anticipated decline is driven by scaling benefits, technological advancements from ongoing research and development, and improved efficiency across the supply chain. For the purposes of 2024 IRP modeling, NIPSCO is benchmarking cost information to RFP data and observed cost premiums for longer-duration storage technology relative to four-hour lithium ion batteries. A single, *representative*, 100-hour technology will be modeled, in accordance with the assumptions summarized in Figure 4-21.

[103] MIT Energy Initiative – "Flow batteries for grid-scale energy storage" and Power Efficiency – "Maximizing Flow Battery Efficiency: The Future of Energy Storage"

Figure 4-21: Long-Term LDES Cost Assumptions



Category	LDES
Fixed O&M (2024$/kW-yr)	$40
Round Trip Efficiency	35%
Tax Credit Eligibility Assumption	40% ITC

Given the expectation that energy storage will be an important part of NIPSCO's long-term portfolio (*see* Section 9 for more information on the key outcomes of the portfolio analysis), NIPSCO will continuously evaluate the landscape of storage options, as technology advances and market conditions evolve. If new LDES technologies emerge with cost and operational parameters consistent with those evaluated in this IRP, NIPSCO will be able to pivot in the implementation of its short-term action plan accordingly. NIPSCO also expects to continue to assess LDES in future IRPs.

4.6.8 Emerging Technologies – Small Modular Reactors

SMRs are a new generation of nuclear fission technology utilizing smaller reactor designs, modular factory fabrication, and passive safety features. SMR can potentially provide a zero-carbon alternative for providing base-load electricity without CO2 emissions, and its siting flexibility and improved safety features potentially allow the technology to be sited closer to demand centers, reducing transmission investments. Key features of an SMR include:

- Small physical footprints;
- Limited on-site preparation, leading to faster construction time and scalability;
- Siting flexibility, including sites previously occupied by coal-fired plants; and
- Passive safety features, allowing the reactor to safely shut down in an emergency without requiring human interventions.

4.6.8.1 SMR Technology Overview

NPPs have long been a significant source of emissions-free, firm energy in the U.S. These facilities harness nuclear fission reactions, in which atoms split and release energy in the form of heat. This heat generates steam by heating water in a reactor core, which drives turbines to produce electricity. Inside the reactor core, fuel rods — comprising small ceramic uranium pellets — are grouped into fuel assemblies and immersed in water, which acts as both a coolant and reaction

moderator. Conventional nuclear reactors can be either PWRs or BWRs. PWRs use high pressures to keep water in the reactor core from boiling. After being heated inside the core, the water is pumped into a heat exchanger, where it boils a secondary source of water into steam and then cycles back to the core. BWRs produce steam inside the reactor core, which is directly fed to a turbine and then recondensed into water to cycle back through the core.

Advanced nuclear energy employs modernized designs that offer a range of environmental, efficiency, safety, and reliability benefits over conventional nuclear.[104] Gen III+ and Gen IV are the two primary categorizations of advanced nuclear technologies. Gen III+ reactors are like conventional reactors in the sense that they use water as a coolant and LEU as a fuel, positioning them for near term deployment.[105] Gen IV reactors use new fuels such as HALEU fuel and novel coolants like molten salt or liquid metal. The approval of NuScale's 60 MW power module by the U.S. NRC marked the first approval of a Gen IV design, underscoring the advancing commercial viability of Gen IV technology.[106]

Several reactor types are in various stages of development and approval, each providing advantages of their own. Conventional water-cooled reactors, also known as light-water reactors, represent the predominant technology in current nuclear power generation. Liquid metal fast reactors, which employ sodium or lead as a coolant, have potential for greatly reducing nuclear waste by consuming fission products with long decay times such as neptunium. Molten salt reactors offer similar fuel reduction benefits and use molten fluoride or chloride salts as a coolant. HTGCRs naturally have high operating temperatures, allowing them to be used for non-electric applications like hydrogen production or desalination. As these reactor types progress through pre-application stages, forthcoming deployments will determine the most suitable candidates for commercial scalability.

Advanced nuclear technologies are further categorized by size, with large reactors operating at around the 1 GW scale, SMRs ranging from 50 to 300 MW, and microreactors sized at 50 MW or less. While each one may have a role to play in the decarbonization of the electric grid by 2050, SMRs have received the most attention given size flexibility and cost improvement potential.[107]

4.6.8.2 Current Operational Landscape

Among the 54 nuclear power plants currently operational in the U.S., there is a combined capacity of 103 GW, constituting about 8% of the nation's total generation capacity in 2023. Due to their high capacity factors, nuclear plants have consistently provided about 20% of U.S. electricity since the 1990s. However, recent growth in nuclear deployments has been slow, with only 2,386 MW of nuclear capacity additions between 2016 and 2023.[108] The most recent additions

104 NEI – "ADVANCED NUCLEAR ENERGY: Frequently Asked Questions for Community Stakeholders"

105 DOE – "Pathways to Commercial Liftoff: Advanced Nuclear"

106 DOE – "NRC Certifies First U.S. Small Modular Reactor Design"

107 Idaho National Laboratories – "Advanced Small Modular Reactors"

108 America's Electricity Generation Capacity Report, 2024 Update (publicpower.org)

to the U.S. nuclear fleet are Units 3 and 4 of the Alvin W. Vogtle Electric Generating Plant, construction of which started in 2009 by Georgia Power. Unit 3 commenced commercial operations on July 31, 2023, followed by Unit 4 on April 29, 2024, collectively adding 2,234 MW of capacity. These units feature the Westinghouse AP1000 Generation III+ reactor, marking the first deployment of advanced nuclear in the U.S.

Some of the early advanced nuclear demonstrations in the U.S. have encountered challenges related to costs and timelines. The Carbon Free Power Project, initiated by Utah Associated Municipal Power Systems in 2015, aimed to build twelve 60 MW NuScale Power Modules. Despite support from DOE funding, the project was terminated in November 2023 before construction began, largely due to cost overruns.[109]

However, several other SMR projects are currently in development or advanced stages. The DOE's Advanced Reactor Demonstration Program is a well-known project launched in 2020 to support advanced nuclear development in the U.S. Through the program, TerraPower's first-of-a-kind Natrium demonstration project — a 345 MW sodium fast reactor with a gigawatt-scale molten salt energy storage system — received $2 billion in DOE funding through a 50/50 cost-share arrangement.[110] The project submitted a construction permit in 2024 and is on track to achieve deployment by 2030, although securing a supply of HALEU remains a critical challenge.[111] X-energy has also partnered with the ARDP to develop the Xe-100 high-temperature gas reactor. The design consists of four 80 MW reactors and can be scaled by adding units to increase electrical output at the same facility. Currently in the process of obtaining a construction permit to build the reactor at a Dow industrial site in Seadrift, Texas, X-energy expects the reactor to be deployed within the decade.[112]

A range of SMR demonstrations are currently progressing through different stages of design, permitting, and construction worldwide. Leading SMR designs under consideration by utilities include the NuScale VOYGR, Holtec International SMR-160, Westinghouse AP300, Rolls-Royce SMR, Kairos Power KP-FHR, Terrestrial Energy Integral Molten Salt Reactor, and TerraPower Molten Chloride Fast Reactor. In the U.S., there are three GW of SMRs in early or pre-development stages, with an additional four GW of announced SMR projects, positioning the country as a leader among the 22 GW of SMR projects in the global pipeline.[113] China achieved a significant milestone by activating the first commercial Gen IV SMR in 2023 and plans to have its first water-cooled SMR online by 2026. Project Phoenix, an initiative by the U.S. Department of State aimed at accelerating global coal-to-SMR conversions, is currently enhancing SMR development in Eastern Europe. The Czech Republic, Poland, Slovakia, and Slovenia are among the initial beneficiaries of the program, receiving support that includes annual workshops on coal to SMR conversion, feasibility studies, site characterization, and advisory services. Feasibility

109 Utility Dive – "NuScale, UAMPS terminate small modular reactor project in Idaho"

110 TerraPower – "TerraPower Natrium"

111 Reuters – "First TerraPower advanced reactor on schedule but fuel a concern"

112 NRC hearing gives information on X-energy, Dow project -- ANS / Nuclear Newswire

113 Utility Dive – "Global small modular reactor pipeline hits 22 GW, with US leading the market: WoodMac"

studies are already underway, with plans to commence SMR operations in these countries by the early 2030s.

While light-water reactor designs are a mature and proven technology, their deployment on the SMR scale in the U.S. is still forthcoming. Gen IV reactors, including sodium reactors, high-temperature gas-cooled reactors, and microreactors, are at earlier stages of technological maturity and advantages and drawbacks.

4.6.8.3 Operational Considerations

SMRs offer numerous advantages over traditional nuclear power plants, particularly in terms of enhanced safety and reduced risk. They are best known for their modular design, which allows for shorter construction times, simpler and more standardized designs, more efficient transportation of components, and lower overall costs, all of which minimize the risk of project abandonment. They also incorporate advanced safety features such as passive safety systems, allowing plants to shut down and self-cool without operator intervention or additional water or power input. Advancements in fuel technology have further minimized the risk of nuclear leakage or meltdown. SMRs can be sited closer to demand centers because of their reduced safety radius, higher power density, and lack of geographical constraints in terms of wind/solar resource availability, which reduces the need for transmission infrastructure that is costly and often difficult to procure. The potential for coal to nuclear power plant conversions could further increase transmission availability and help reduce capital costs.

SMRs offer significant reliability benefits, including firm power, load-following capabilities, and black start capability.[114] They achieve high capacity factors ranging from 80% to 95% and have high peak capacity accreditation, allowing them to ensure stable energy supply across seasons, protect against blackouts, and maintain a reasonable reserve margin year-round. Their ability to integrate electricity into the grid or operate independently makes them suitable for powering critical facilities such as hospitals, military bases, or isolated communities. Other diverse use cases including hydrogen generation, industrial heat production for chemical plants and refineries, and desalination of water for municipalities bolsters their grid flexibility. The modular design of SMRs allows for refueling and maintenance on individual reactors without requiring an outage of the entire facility, which translates to reduced operational downtime. Moreover, their capability for multi-year on-site fuel supply addresses fuel security concerns, particularly in winter when extreme cold weather may disrupt fuel production and delivery.

SMRs embody several environmental advantages typical of advanced nuclear technologies. They feature low life cycle emissions compared to major generation sources, zero emissions during power generation, and less toxic waste than conventional NPPs.[115] Nuclear energy also boasts the highest electrical capacity per acre of land among major energy sources. It produces approximately 57,000 MWh/year per acre, with the next highest being geothermal at

114 DOE – “5 Key Resilient Features of Small Modular Reactors”; and Small Modular Reactors – “SMR load-following capabilities”

115 NREL – “Life Cycle Assessment Harmonization | Energy Analysis”

9,000 MWh/year per acre.[116] These environmental benefits help mitigate challenges associated with high land costs, permitting complexities, spent fuel storage, and emissions regulations.

4.6.8.4 Federal Policy Support

Advanced nuclear technologies can receive the federal PTC or ITC as per the IRA provisions that make them available for new plants with zero greenhouse gas emissions that commence operations after December 31, 2024. Additionally, legislation will play a major role in enabling the significant capacity increases that will be needed across the nuclear supply chain. Recently, the ADVANCE Act was signed into law,[117] encouraging first movers by reducing NRC licensing and applications fees, introducing large prize competitions, directing the NRC to establish a licensing and regulation process for microreactors, supporting reuse of brownfield sites for nuclear energy, and strengthening domestic HALEU availability.

4.6.8.5 SMR Cost Considerations

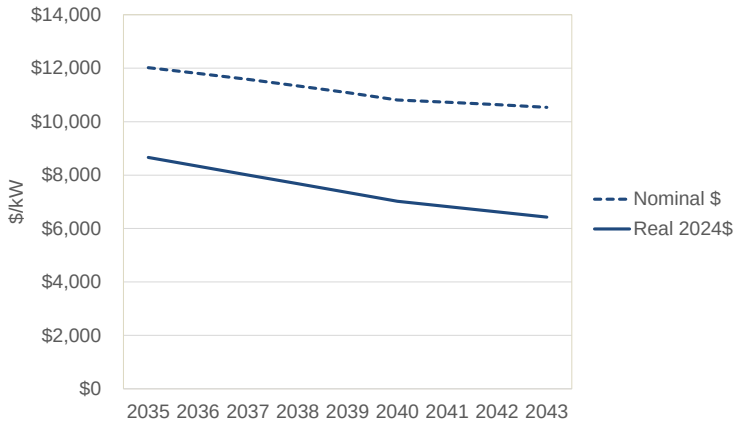
In general, SMRs are characterized by high capital costs and relatively low variable costs. Their small size and modular designs enable mass production, rapid assembly of components, and transportation of entire units, leading to significantly reduced financing and capital expenses relative to larger plants. While refined uranium fuel prices introduce some cost uncertainty, they constitute a smaller portion of operating expenditures compared to natural gas electricity generation, thus mitigating fuel price risks.

Recent nuclear projects in the U.S. have reported overnight capital costs around $10,000/kW. While the DOE estimates that deploying 10-20 reactors at a 12% to 15% learning rate could result in significant learnings and cost efficiencies over time, future costs remain highly uncertain. For modeling purposes, NIPSCO is assuming availability in 2035 and beyond, with cost estimates taken from NREL's ATB, as documented in Figure 4-22.

116 DOE – "Pathways to Commercial Liftoff: Advanced Nuclear".

117 DOE – "Newly Signed Bill Will Boost Nuclear Reactor Deployment in the United States"

Figure 4-22: Long-Term SMR Cost Assumptions



Category	Assumption
Fixed O&M (2024$/kW-yr)*	$144
First Available Year	2035
Tax Credit Eligibility Assumption	30% ITC

**NREL ATB assumptions for 2035 benchmark year*

4.6.9 Long-Term Uncertainties with Emerging Technologies

NIPSCO recognizes that the landscape for all emerging technologies is subject to significant change over the long term, particularly as associated with technology evolution, federal policy initiatives, and investment from developers and public authorities. NIPSCO is committed to maintaining flexibility in its future resource decisions and expects to continue tracking the following uncertainties associated with emerging technology deployment:

- Technology advancement associated with electrolyzer costs, nuclear technologies, LDES technologies, and CCUS;
- The evolution of federal incentives, including direct subsidies or other federal investment;
- Developments in hydrogen transmission, distribution, and storage infrastructure and how they interact with current natural gas infrastructure;
- MISO market dynamics, including the potential for evolving value opportunities associated with capacity accreditation, renewable curtailment risk (which could otherwise be diverted to hydrogen production or LDES charging), or local congestion;
- Broader carbon emission reduction policies, which could put a price on carbon or further incentivize the use of clean energy sources.

4.6.10 Federal Tax Incentives for Clean Energy Resources

Federal tax incentives are currently in place for clean energy and storage resources as a result of the passage of the IRA in 2022. Clean energy resources are eligible for a PTC or an ITC, while storage resources are eligible for the ITC. In addition, federal tax credits are available for

the geological sequestration of carbon dioxide emissions and the production of green hydrogen. Figure 4-23 provides a summary of key federal tax credits relevant to new resource options for NIPSCO's portfolio.

Figure 4-23: Summary of Available Federal Tax Credits for Clean Energy

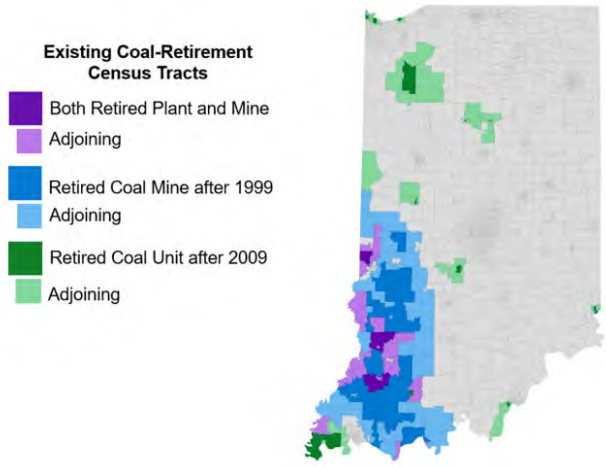
In-Service Year[6]	Production Tax Credit[1, 2]	Investment Tax Credit[1, 2]	CCS (Section 45Q)[1]	Hydrogen PTC (Section 45V)[1, 3]
	10-year $/MWh	*Up front portion of investment*	*12-year $/metric ton-CO2*	*10-year $/kg*
	$30/MWh in 2024$[5]	*%*	*$85 in 2026$[5]*	*$3/kg[4] in 2022$[5]*
2024-2035	100% of value	30%	Available	Available
2036	75% of value	22.5%		
2037	50% of value	15%		
2038+	0%	0%	$0	$0

Notes:
1. Assumes prevailing wage and apprenticeship requirements met.
2. A 10% "energy community" bonus is available for projects located in proximity to retired coal infrastructure or in statistical areas with high historical employment in the fossil fuel sector and unemployment rates greater than the national average. The bonus adds 10% to the ITC and increases the PTC amount by 10%.
3. For modeling purposes, NIPSCO is assuming a price for hydrogen (net of tax credits) rather than investment in an electrolyzer and associated green hydrogen production. Since the hydrogen PTC has a 10-year term, tax credits are expected to be eligible for hydrogen fuel purchased through the fundamental modeling horizon through 2043.
4. Assuming green hydrogen with a lifecycle emission rate below 0.45 kg CO2e/kg-H2.
5. The tax credit values are tied to inflation. Baseline years are provided for reference.
6. Tax credit eligibility is defined by commence construction dates. For modeling purposes, safe harbor construction periods are assumed, and these assumptions are presented for projects entering into service during the specified years.

The IRA provides a schedule of tax credit phaseouts over time based on the resource's begin construction date. Some of the phaseout schedules are dependent on U.S. power sector emissions achieving a 75% reduction from 2022 baseline levels, although for modeling purposes, NIPSCO assumes tax credit eligibility in line with the dates summarized in Figure 4-23. NIPSCO's scenario analysis also incorporates one scenario in which tax credits are phased out earlier (see details in Section 8).

In addition to the tax credit levels outlined in Figure 4-23, the IRA offers a 10% "energy community" bonus for projects located in proximity to retired coal infrastructure or in statistical areas with high historical employment in the fossil fuel sector and unemployment rates greater than the national average. Several such sites exist in NIPSCO's service territory and Indiana as a whole. The bonus adds 10% to the ITC and increases the PTC amount by 10%. Based on RFP data and recent NIPSCO project experience, several new resource types are assumed to be eligible for the 10% energy community bonus.

Figure 4-24: IRA Energy Community Bonus Areas in Indiana



NIPSCO has the ability to monetize federal tax credits for the benefit of customers through a variety of pathways, including:

- Via a PPA where tax credits flow to the developer and are reflected in PPA pricing;
- Via direct ownership of a project, where NIPSCO can directly monetize tax credits against its federal tax liability;
- Via direct ownership of a project, where NIPSCO can sell tax credits for cash to a third party through the tax credit transfer provisions in the IRA;
- Via a joint venture with a tax equity partner, where a third-party tax equity investor would invest to obtain a specified internal rate of return through the receipt of tax benefits in the form of depreciation, tax credits, and cash for a specified time frame. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.

NIPSCO's tax credit monetization strategy will be project-specific and thus not evaluated in detail in the IRP. For modeling purposes, NIPSCO has assumed monetization either through PPAs or direct ownership and potential tax credit transfer. Based on available resource cost and operational data, the following tax credit assumptions were made: solar: 40% ITC; storage: 40% ITC; wind: PTC; SMR: 30% ITC; CCUS: 45Q credit at $85/ton (real 2026$).

Section 5. Demand-Side Resources

5.1 Existing Resources

5.1.1 Existing Energy Efficiency Resources

NIPSCO actively promotes energy conservation and efficiency to customers and works with its contractors to offer cost-effective energy efficiency programs. On October 18, 2023, the Commission issued a Final Order in Cause No. 45849 approving a Settlement Agreement among NIPSCO, the Indiana Utility Consumer Counselor, and the Citizens Action Coalition of Indiana, Inc., which included NIPSCO's proposed EE programs for the period of January 1, 2024 through December 31, 2026 (the "2024-2026 Plan"). To support the continuation of its program offerings for the period 2024 through 2026, NIPSCO recommended, and its OSB approved, TRC as the vendor to continue implementing both its residential and C&I programs. The OSB also agreed that ILLUME Advising would continue as the EM&V vendor for the three program years.

2024-2026 Residential Programs

Home Rebates

The Home Rebates program is designed to provide incentives to residential customers to replace inefficient HVAC equipment and other home products with energy-efficient alternatives. These measures are paid per-unit installed, reimbursing customers for a portion of their cost. The program's intent is to help remove the financial barrier associated with the initial cost of these energy-efficient alternatives. The electric program promotes premium efficiency air conditioners, air conditioner tune-ups, smart thermostats, ENERGY STAR® air purifiers, ENERGY STAR dehumidifiers, ENERGY STAR clothes dryers, ductless mini-split heat pumps, ENERGY STAR pool pumps, heat pumps, and heat pump water heaters. This program will also offer products through a midstream channel that works with distributors.

Retail Products

The Retail Products program is designed to increase the purchase and use of energy-efficient products among NIPSCO's residential electric customers. The program provides instant discounts by using upstream wholesale incentives to buy down the incremental costs on products such as lighting fixtures, air purifiers, and smart power strips.

Home Energy Analysis

The Home Energy Analysis program is designed to help eligible customers improve the efficiency and comfort of their homes, as well as deliver an immediate reduction in electricity (in kWh) consumption and promote additional efficiency work. This program will provide homeowners with the direct installation of no-cost, energy-efficient measures followed by the delivery of a Comprehensive Home Assessment report to the customer. This program is unique in that it provides a whole home assessment leading to easy to achieve kWh savings opportunities. TRC will continue to utilize a qualified subcontractor for the implementation of this program.

Appliance Recycling

The Appliance Recycling program is designed to provide an incentive to residential customers who choose to recycle a qualifying primary or secondary working refrigerator and/or freezer, room air conditioner, and dehumidifier. TRC will utilize a qualified subcontractor for the implementation of this program.

School Education

The School Education program is designed to produce electric savings by influencing fifth grade and high school students and their families to focus on the efficient use of electricity. It will provide classroom instruction, posters, and activities aligned with national and state learning standards and energy education kits filled with energy-saving products and advice. Students will participate in an energy education presentation at school, learning about basic energy concepts through class lessons and activities. Students will also receive an energy education kit of quality, high-efficiency products and are instructed to install the energy-efficient products at home with their families as well as complete a worksheet. The experience at home will complete the learning cycle started at school. TRC will continue to utilize a qualified subcontractor for the implementation of this program.

Multi-Family Direct Install

The Multi-Family Direct Install program is designed to provide a “one-stop shop” to multifamily building owners, managers, and tenants of multifamily units containing three or more residences receiving service from NIPSCO. With flexible and affordable options, the program generates immediate energy savings and improvements in two distinct program phases. Phase I is a walkthrough assessment of each property, which is conducted to determine eligibility for direct installation services provided by the program, along with complementary incentive offers available through other NIPSCO programs. Property managers are presented with an Energy Improvement Plan that prioritizes recommendations along with a proposal to provide the direct installation services outlined in Phase II. Phase II is an in-unit direct installation of energy-efficient devices at no cost or low cost to the tenant or landlord, such as downlight fixtures, low-flow showerheads, faucet aerators, pipe wrap, and programmable thermostats. Educational materials about home operation, maintenance, and behavior that may reduce energy consumption are provided to tenants in each living unit. To encourage participation, property managers may be paid an incentive upon

completion of the project. TRC will continue to utilize a qualified subcontractor for the implementation of this program.

Residential New Construction

The Residential New Construction program is designed to increase awareness and understanding by home builders of the benefits of energy-efficient building practices, with a focus on capturing energy efficiency opportunities during the design and construction of manufactured and other single-family homes. This program produces long-term, cost-effective savings by incentivizing builders to achieve the various Home Energy Rating System tiers, along with strategies for incorporating the Silver, Gold, and Platinum designations into their marketing efforts to attract home buyers.

HomeLife Energy Efficiency Calculator

The HomeLife Energy Efficiency Calculator program is designed to offer NIPSCO's residential customers an online "do-it-yourself" audit and an energy savings kit for carrying out the audit, at no cost to the customer. The audit tool effectively: (1) identifies low-cost/no-cost measures that a NIPSCO residential customer can easily implement to manage electric consumption; (2) allows eligible customers to request a free home energy kit; (3) educates customers about the variety of programs available to them through the residential energy efficiency portfolio; and (4) assists customers in finding qualified and experienced contractors through a network of trade allies.

Income Qualified Weatherization

The Income Qualified Weatherization program is designed to provide energy efficiency services to qualifying low-income households. For a household to be eligible to participate in the IQW program, the customer must be a NIPSCO residential customer with active service who receives Low-Income Home Energy Assistance, Temporary Assistance for Needy Families, Supplemental Security Income, or Supplemental Security Disability Income and has not received weatherization services in the past three years from the date of application. Qualifying participants receive the direct installation of no-cost energy efficiency measures, including a refrigerator replacement, and a Comprehensive Home Assessment to identify areas of the home where additional energy savings can be achieved to make the home more comfortable and reduce energy costs.

Residential Online Marketplace

The Residential Online Marketplace program provides an online store for NIPSCO electric customers to purchase and install EE measures with an instant incentive applied at the time of purchase. The Residential Online Marketplace ensures only NIPSCO customers are eligible to purchase, and limits are set on the quantities purchased to ensure timely installation.

Home Energy Report

The Home Energy Report program (also known as the Behavioral program) is designed to encourage energy savings through behavioral modification. The program provides customers with home energy reports that contain personalized information about their energy use and provides ongoing recommendations to make their homes more efficient. Customers will be randomly chosen to participate in the program and may opt out if they do not wish to participate. The reports engage customers and drive them to take action to bring their energy usage in line with similar homes and encourage participation in other complimentary residential programs. The program empowers customers to understand their energy usage better and uses competition through neighbor comparisons to influence customers to act on this knowledge, resulting in changed behavior.

Income Qualified Home Energy Report

The Income Qualified Home Energy Report program (also known as the Income Qualified Behavioral program) is designed to encourage energy savings through behavioral modification. The program provides income qualified customers with home energy reports (print and email) that contain personalized information about their energy use and provide ongoing recommendations to make their homes more efficient as well as at-risk language to support customers with energy saving tips, ways to seek additional assistance from utility, local, state, and federal agencies and inform them of potential higher than average usage compared to prior months before receiving their bill. Customers are randomly chosen to participate in the program and may opt out if they do not wish to participate. The reports engage customers and drive them to take action to bring their energy usage in line with similar homes and encourage participation in other complimentary residential programs, including programs offered both by NIPSCO and by other entities focused on income qualifications. The program empowers customers to understand their energy usage better and uses competition through neighbor comparisons to influence customers to act on this knowledge, resulting in changed behavior. Table 5-1 shows the projected energy savings (MWh) by year for each of the Residential programs.[118]

[118] **Error! Reference source not found.** Table 5-1 represents incremental, gross savings at the meter from the plan approved by the Commission in Cause No. 45849. On a net basis, inclusive of measure life considerations, the annual, cumulative impacts modeled for IRP purposes are slightly different. In addition, at the time of the development of the DSM inputs for the IRP, slightly different adjustments were applied to the near-term DSM savings expectations, resulting in slightly different numbers used for IRP modeling purposes. However, given that these savings are part of the plan approved by the Commission, they were universally applied across all portfolios and do not impact comparisons across portfolio options.

Table 5-1: 2024-2026 Projected Residential Energy Savings (MWh)

Residential Programs	2024	2025	2026	2024-2026
Home Rebates	2,404	3,795	5,128	11,327
Retail Products	5,884	5,917	5,967	17,768
HEA	614	650	691	1,955
Appliance Recycling	2,226	2,449	2,694	7,369
School Education	1,568	1,568	1,568	4,704
MFDI	1,466	1,592	1,731	4,789
Residential New Construction	605	661	723	1,989
HomeLife EE Calculator	276	276	276	828
IQW	1,076	1,132	1,193	3,401
Residential Online Marketplace	824	856	878	2,558
Home Energy Report	19,674	21,162	21,460	62,296
Income Qualified Home Energy Report	6,646	6,178	5,660	18,484
Total Residential Programs	43,263	46,236	47,969	137,468

Table 5-2 shows the annual total program budget for each of the Residential programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[119]

[119] In its Final Order, the Commission approved that NIPSCO (with OSB approval) is authorized to increase any individual program funding by up to 20% of the total program budget, even if this exceeds the overall 2024-2026 DSM Plan budget approved by the Commission. These budgets do not reflect the potential adjustment.

Table 5-2: 2024-2026 Residential Program Budget

	2024	2025	2026	Total
Home Rebates	$ 2,534,082	$ 3,587,890	$ 4,460,734	$10,582,706
Retail Products	$ 1,361,527	$ 1,219,595	$ 1,078,262	$ 3,659,384
HEA	$ 436,364	$ 458,753	$ 484,960	$ 1,380,077
Appliance Recycling	$ 427,664	$ 408,394	$ 380,993	$ 1,217,051
School Education	$ 988,365	$ 963,449	$ 939,047	$ 2,890,861
MFDI	$ 897,666	$ 939,095	$ 981,935	$ 2,818,696
Residential New Construction	$ 130,979	$ 126,220	$ 119,537	$ 376,736
HomeLife EE Calculator	$ 133,021	$ 127,341	$ 121,704	$ 382,066
IQW	$ 1,171,491	$ 1,239,900	$ 1,316,365	$ 3,727,756
Residential Online Marketplace	$ 379,332	$ 391,251	$ 397,021	$ 1,167,604
Home Energy Report	$ 1,050,182	$ 918,357	$ 918,357	$ 2,886,896
Income Qualified Home Energy Report	$ 521,447	$ 455,097	$ 455,097	$ 1,431,641
Total Residential Programs	$10,032,120	$10,835,342	$11,654,012	$32,521,474

2024-2026 C&I Programs

Prescriptive

The Prescriptive program is designed to provide incentives for a set list of energy-efficient measures and will be paid based on per unit installed, reimbursing the customer for a portion of the cost. The Prescriptive program will offer incentives to NIPSCO's C&I customers who are making electric EE improvements in existing buildings.

Custom

The Custom program will be available to C&I customers for installing new energy-saving equipment. Custom incentives are designed for more complicated projects, RCx projects, or projects that incorporate alternative technologies. Project pre-approval will be required for all Custom incentives to ensure that only cost-effective projects are approved. Qualifying measures will be required to have a Total Resource Cost test score greater than 1.0, have a simple payback greater than 12 months (less than 12 months for RCx measures), and cannot be included as an EE measure in the Prescriptive Program. RCx projects examine energy consuming systems for cost-

effective savings opportunities. The RCx process identifies operational inefficiencies that can be removed or reduced to yield energy savings.

C&I New Construction

The C&I New Construction program is designed to encourage construction of energy efficient C&I facilities within the NIPSCO service territory. This program will offer financial incentives to encourage building owners, designers, and architects to exceed standard building practices and achieve efficiency, above and beyond the 2010 Indiana Energy Conservation Code. The goal of the New Construction program is to produce newly constructed and expanded buildings that are efficient from the start. New construction projects that may be eligible for incentives under the New Construction program may include any of the following: (1) new building projects wherein no structure or site footprint presently exists; (2) addition to or expansion of an existing building or site footprint; and (3) a total "gut" rehabilitation for a change of purpose requiring replacement of all electrical and mechanical systems/equipment.

Small Business Direct Install

The Small Business Direct Install program is designed to facilitate participation in the NIPSCO business EE program of small C&I customers that do not possess the in-house expertise or capital budget to develop and implement an energy efficiency plan. The program will offer a variety of ways for small businesses, with billing demands not exceeding 200 kW, to improve the efficiency of their existing facilities. Measures will be paid out on a per-unit basis, much the same way as the Prescriptive program, but with slightly higher incentive rates in an effort to encourage energy efficient investment from these smaller commercial customers. Incentive payments to the approved trade allies will occur following measure implementation and submission of all required paperwork. If additional incentives are available through other programs, customers will be directed to the appropriate application.

C&I Online Marketplace

The C&I Online Marketplace program will provide an online store for NIPSCO electric customers to purchase and install EE measures with instant incentive applied at the time of purchase. The C&I Online Marketplace program will ensure only NIPSCO customers are eligible to purchase, and limits are set on the quantities purchased to ensure timely installation.

Strategic Energy Management

The Strategic Energy Management program will provide NIPSCO customers with a tailored self-service platform when they opt in to the program. The platform will provide customers with the knowledge and insights to make meaningful and energy-efficient choices in their facilities. Through personalized energy efficiency suggestions, the program will provide uplift to other C&I programs while providing behavioral savings based upon the changes made at the facility outside of other commercial and industrial programs.

Table 5-3 shows the projected energy savings (MWh) by year for each of the C&I programs.[120]

Table 5-3: 2024-2026 Projected C&I Energy Savings (MWh)

C&I Programs	2024	2025	2026	Total
Prescriptive	25,975	26,701	25,710	78,386
Custom	32,779	31,297	29,917	93,993
C&I New Construction	13,662	13,045	12,469	39,176
SBDI	1,574	1,504	1,437	4,515
C&I Online Marketplace	3,936	3,758	3,592	11,286
SEM	787	752	718	2,257
Total C&I Programs	**78,713**	**77,057**	**73,843**	**229,613**

Table 5-4 shows the total annual program budget for each of the C&I programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.

Table 5-4: 2024-2026 C&I Program Budget

C&I Programs	2024	2025	2026	Total
Prescriptive	$ 4,496,951	$ 5,083,376	$ 4,965,423	$14,545,750
Custom	$ 5,817,162	$ 5,570,304	$ 5,742,130	$17,129,596
C&I New Construction	$ 2,319,671	$ 2,262,194	$ 2,299,311	$ 6,881,176
SBDI	$ 341,431	$ 332,587	$ 328,620	$ 1,002,638
C&I Online Marketplace	$ 700,442	$ 705,736	$ 712,239	$ 2,118,417
SEM	$ 142,622	$ 138,905	$ 137,405	$ 418,932
Total C&I Programs	**$13,818,279**	**$14,093,102**	**$14,185,128**	**$42,096,509**

[120] Table 5-3 represents incremental, gross savings at the meter from the Final Order in Cause No. 45849. At the time of the IRP, slightly different adjustments were used for modeling but were universally applied.

Table 5-5 shows the projected energy savings (MWh) by year for all Residential and C&I programs included in the 2024-2026 Plan. NIPSCO also included Emerging Technologies in the plan for programs and measures that have not yet been identified.

Table 5-5: 2024-2026 Projected Combined Energy Savings (MWh)

	2024	2025	2026	Total
Total Residential Programs	43,263	46,236	47,969	137,468
Total C&I Programs	78,713	77,057	73,843	229,613
Emerging Technologies				8,041
Total 2024-2026 Plan	**121,976**	**123,293**	**121,812**	**375,122**

Table 5-6 shows the annual total program budget for all Residential, C&I, and Emerging Technology programs included in the 2024-2026 Plan.

Table 5-6: 2024-2026 Combined Program Budget

	2024	2025	2026	Total
Total Residential Programs	$10,032,120	$10,835,342	$11,654,012	$32,521,474
Total C&I Programs	$13,818,279	$14,093,102	$14,185,128	$42,096,509
Emerging Technologies				$ 1,859,883
Total 2024-2026 Plan Budget	**$23,850,399**	**$24,928,444**	**$25,839,140**	**$76,477,866**

Table 5-7 shows the eligible customer classes and rate schedules for each of the Residential and C&I programs included in the 2024-2026 Plan.

Table 5-7: Eligible Customers

Program	Customer Class	Electric Rate Schedule
Home Rebates	Residential	511
Retail Products	Residential	511
HEA	Residential	511
Appliance Recycling	Residential	511
School Education	Residential	511
MFDI	Residential	511
Residential New Construction	Residential	511
HomeLife EE Calculator	Residential	511
IQW	Residential	511
Residential Online Marketplace	Residential	511
Home Energy Report	Residential	511
Income Qualified Home Energy Report	Residential	511
Prescriptive	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
Custom	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
C&I New Construction	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
SBDI	C&I	520, 521, 522, or 523 who have not had a billing demand of 200 kW or greater in any month during the previous 12 months
C&I Online Marketplace	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
SEM	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544

5.1.2 Existing Demand Response Resources

5.1.2.1 Capacity Resources

On December 4, 2019, the Commission issued a Final Order in Cause No. 45159, which revised its industrial service structure by removing Rider 775 and Rate 734 and added Rate 831 and the Commission approved the continuation of this industrial rate structure in Cause No. 45772 with Rate 531 (formerly Rate 831). This industrial service structure requires NIPSCO's largest industrial customers on Rate 531 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR, which is, by definition, curtailable. NIPSCO experienced an increase in registered LMRs as a result of this new industrial power service structure, unless those Rate 531 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, large industrial customers will continue to be eligible to participate in MISO's DR Resource program, discussed below.

5.1.2.2 Energy-Only Resources

NIPSCO offers DRR1 and EDR through Riders 581 and 582, respectively. These Riders are available to a customer on Rates 523, 524, 525, 526, 531, 532, and 533 that has a consistent ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as dispatched by MISO. Through these Riders, the Customer or Aggregator of Retail Customer curtails a portion of its electric load through participation with the Company, acting as the Market Participant with MISO. These Riders are available to any load that is participating in the Company's other interruptible or curtailment Riders, unless MISO rules change and do not permit load used by the Company as a LMR to also participate as a DRR1 or EDR. Although the DRR1 and EDR offered under Riders 581 and 582, respectively, do not qualify as a Capacity Resource, they do offer a means for customers to offer into the MISO market and to be paid for the portion of their electric load curtailed. This provides economic benefit to the customers participating in these Riders and to other NIPSCO customers through an overall lower electric system demand, which can help NIPSCO to avoid purchased power or the need for higher cost generation resources to be committed through the MISO market. Currently, NIPSCO has one customer participating in Rider 581 as a DRR1. No customers are participating in Rider 582 as an EDR.

5.2 DSM MPS

5.2.1 DSM MPS – Purpose and Key Objectives

To support the IRP and DSM planning for NIPSCO, NIPSCO contracted with the GDS Team to conduct a DSM MPS (a copy of which is included in Appendix B). The DSM MPS provides an update of DSM program costs and savings for a 20-year time horizon (2027-2046).[121]

[121] Near term (2025-2026) savings in the IRP are informed by NIPSCO's currently approved DSM Plan. Based on discussions with the NIPSCO OSB, it was agreed that the DSM MPS would be used to inform the remaining years of the IRP.

The study included a comprehensive review of current programs, historical savings, and projected energy savings opportunities in order to develop estimates of technical, economic, and achievable potential. Separate estimates of energy efficiency and demand response potential were developed. The effort was highly collaborative, as the GDS Team worked closely with the NIPSCO OSB to produce reliable estimates of future savings potential, using the best available information and best practices for developing market potential savings estimates.

5.2.2 Impact of Opt-out Customers

The GDS Team reviewed the latest information available from NIPSCO related to energy efficiency program participation, measure and program savings data, results of NIPSCO's 2021 MPS, NIPSCO's electric load and customer forecasts, NIPSCO's load research data, electric avoided costs, program evaluation reports, and NIPSCO's 2024-2026 DSM Plan. NIPSCO requested that GDS prepare its base case DSM market potential assuming that C&I electric customers, who had opted out of NIPSCO's energy efficiency programs prior to January 1, 2023, would be excluded from the DSM MPS. In Indiana, commercial or industrial customers with a peak load greater than 1 MW are eligible to opt out of utility-based electric energy efficiency programs. In the NIPSCO service area, approximately 11% of commercial kWh sales have opted out of utility-based electric energy efficiency programs, while roughly 81% of industrial kWh sales have opted out.

5.2.3 Modeling Framework

The GDS Team used its energy efficiency and DR planning models to prepare the DSM MPS. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, savings of other fuels, and benefit/cost ratios over the planning horizon. These models are transparent and all formulas, model inputs, and model outputs can be viewed by the model user.

5.2.4 Key Assumptions That Impact Energy Efficiency Potential

The GDS Team updated several input assumptions during the process of preparing the DSM MPS. The changes made for a few of these input assumptions are discussed below.

5.2.4.1 Updated NIPSCO Load Forecast, Avoided Cost Forecast and General Planning Assumptions

NIPSCO and CRA, provided the GDS Team with an electric load forecast for 2024 through 2046. GDS used this load forecast to calculate the percentage of electric MWH sales and peak demand saved each year by DSM programs. Without hyperscaler data center load, NIPSCO's load forecast projects that total MWh sales to ultimate customers will only increase 0.1% per year, on average, through the year 2043. For energy efficiency, the load forecast absent any potential new hyperscaler data center load was utilized because these potential new loads would likely be eligible to opt out of the energy efficiency charge. These additional loads were considered in development of the demand response potential.

NIPSCO also provided GDS with updated planning assumptions for avoided energy, avoided capacity, and avoided transmission and distribution costs, the general inflation rate, escalation rates for NIPSCO electric rates, the utility discount rate, line losses by class of service, and the planning reserve margin.[122] GDS used these assumptions to develop the 2024 MPS.

5.2.4.2 NIPSCO DSM Assumptions for Measure Costs, Savings, Useful Lives, and Market/Equipment Characteristics

GDS reviewed the assumptions for measure costs, savings, and useful lives included in the 2024-2026 NIPSCO DSM plan and updated these assumptions where appropriate. GDS utilized data specific to NIPSCO when it was available and current. GDS used the most recent NIPSCO evaluation report findings (as well as NIPSCO program planning documents), the recently updated Indiana TRM, the Illinois TRM, and the Michigan Energy Measures Database to inform a large portion of the data requirements. Additional data sources were only used if these sources either did not address a certain measure or contained outdated information. Additional source documents included the NREL Energy Measures Database, American Council for an Energy-Efficient Economy research reports, and other market potential study databases.

In addition to measure assumption development, the GDS Team developed estimates of equipment penetration, saturation, and efficiency characteristics, as well as customer willingness to participate in program offerings data, across select end-uses/technologies. GDS primarily leveraged the market research results from the 2021 NIPSCO MPS, which included a combination of online/mail surveys, as well as a limited amount of on-site site visits, to form the basis of the research. The resulting data was used to develop updated estimates of baseline and efficient equipment saturation estimates in the market potential study and to develop expected long-term adoption rates for energy efficiency over the study horizon.

5.2.4.3 Federal Efficiency Standards and Tax Rebates

The DOE develops and implements federal appliance and equipment standards to improve energy efficiency, saving consumers energy and money. The DOE is currently required to periodically review standards and test procedures for more than 60 products, representing about 90% of home energy use, 60% of commercial building energy use, and 30% of industrial energy use. By law, the DOE is expected to review each national appliance standard every six years and publish either a proposed rule to update the standard or determine that no change to the existing standard is needed. The sources used to develop measure assumptions for the study reflect recent updates to federal efficiency standards. Although not exhaustive, key measures that have been impacted by updates to federal standards since the prior MPS include:

- Residential air-source heat pumps in 2023

[122] NIPSCO provided the GDS Team with both average and peak line loss factors. The GDS Team used the peak line loss factors (LLF) to adjust savings at the meter to the generator-level. NIPSCO has not conducted a marginal versus average line loss study, but the use of the peak LLF for DSM impacts is used as a proxy for the marginal LLF. The peak residential line loss used in the analysis was 7.5%.

- Residential central air conditioners in 2023
- Commercial single-package and split system unitary air conditioners in 2023

In addition to accounting for federal efficiency standards, the study recognized the implications of federal tax credits and rebates. The IRA includes various pathways for residents to receive credits and/or rebates for installing energy efficiency measures. The study accounted for the IRA in multiple ways, including in the assessment of measure-level cost-effectiveness and estimating how the rate of adoption of energy efficiency measures could be impacted by the availability of federal tax rebates and credits. The study also estimated what portion of future savings potential may be attributable to programs aligned with federal funding versus what could be achieved by NIPSCO. This is addressed further in Section 5.3 Future Resource Options.

5.2.5 Energy Efficiency Measures & Potential

5.2.5.1 Measures Considered

For the residential sector, there were 197 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-8 provides a summary of the types of measures included for each end use in the residential sector. The measure list was developed based on a review of current NIPSCO programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. The residential measures were then further broken out to include permutations across housing type (single-family vs. multifamily) and income type (income-qualified vs. market rate).

Table 5-8: Types of Electric Energy Efficiency Measures included in the Residential Sector Analysis[123]

End Use	Measure Types Included		
Appliances	ENERGY STAR Air Purifier ENERGY STAR Refrigerator Refrigerator Recycling ENERGY STAR Clothes Washer ENERGY STAR Dishwasher Ultrasonic Clothes Dryer	ENERGY STAR Dehumidifier Dehumidifier Retirement ENERGY STAR Freezer Freezer Recycling ENERGY STAR Clothes Dryer	Heat Pump Dryer Ozone Laundry Smart Dryer Sensor ENERGY STAR Water Coolers Induction Cooktop
Audit	Assessment Recommendations		
Behavioral	Home Energy Reports Home Energy Management System AMI Data Portal		
Consumer Electronics	Advanced Power Strip – Tier 1 Tier 2 Advanced Power Strips (APS) – Residential Audio Visual		

[123] Some of the unique measures have been collapsed into broader categories to summarize the list.

End Use	Measure Types Included		
	ENERGY STAR Television Smart Sockets		
Electric Vehicle Charging	L2 ESVE		
HVAC Equipment	ASHP 15.2 SEER2 ASHP 16.2 SEER2 ASHP 17.1 SEER2 ASHP 18.1 SEER2 Ground Source Heat Pump Ductless HP 8.5 HSPF2 Ductless HP 9.4 HSPF2 Ductless HP 10.8 HSPF2 Ductless HP 11.7 HSPF2 AC Tune Up Central AC 15.2 SEER Central AC 16.2 SEER	Indirect-Evaporative Cooler Radiant Panels Advanced Wall Heater Wi-Fi Smart Thermostat Programmable Thermostat Optimized Thermostat Integrated HVAC Controls ECM HVAC Motor Advanced Furnace Fan ENERGY STAR Room AC Room AC Recycling Smart Vents/Sensors	Whole House Attic Fan HVAC Economizer Efficient Bathroom Fan ENERGY STAR Ceiling Fan Energy Recovery Ventilator Filter Cleaning/Replacement Efficient Kitchen Fan Eco-Snap Air Conditioning Residential Wet Bulb Chiller Solar-Assisted AC Electro Caloric Heat Pump
Lighting	LED A-line LED Globe LED PAR/R/BR LED Candelabra LED Nightlights Exterior LED Lamp	LED String Lighting Linear LED LED Fixture Occupancy Sensor Exterior Lighting Controls LED Exit Signs	Connected LED Lamps EISA Exempt LED Ultra-Efficient LED Advanced Lighting
New Construction	ENERGY STAR New Home Integrated Design		
Pools/Pumps	Heat Pump Swimming Pool Heater Variable Speed Pool Pump	Pool Timer Well Pump	
Shell	Duct Sealing Air Sealing Basement Sidewall Insulation Floor Insulation Above Crawlspace Wall Insulation Advanced Walls Insulation Ceiling/Attic Insulation	Rim/Band Joist Insulation Low-E Storm Window High Performance Windows Insulated Cellular Shades Multifamily Whole Building Aerosol Sealing Insulated Concrete Forms	Phase Change Blanket Basement Wall InsulationNanoinsulation Ceiling / Attic Insulation Nanoinsulation Crawlspace InsulationNanoinsulation Floor InsulationNanoinsulation Rim and Band Joist Insulation - Nanoinsulation Wall InsulationNanoinsulation
Water Heating	Water Heater Temperature Setback Domestic Hot Water Pipe Insulation Bathroom Aerator 1.0 gpm	Thermostatic Restrictor Shower Valve Heat Pump Water Heater (UEF 2.0)	Water Heater Wrap Drain-water Heat Recovery Shower Timer Recirculating Pump Controls

End Use	Measure Types Included	
	Kitchen Flip Aerator 1.5 gpm Low Flow Showerhead 1.5 gpm	Heat Pump Water Heater (UEF 2.6) Water Heater Timer

For the C&I sector, there were 272 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-9 provides a summary of the types of measures included for each end use in the C&I sector. Measures are assumed to be included as part of NIPSCO's current portfolio of offerings, either under their current Prescriptive or Small Business Direct Install programs, or under the Custom program offering.

Table 5-9: Types of Electric Energy Efficiency Measures included in the C&I Sector Analysis

End Use	Measure Types Included		
Compressed Air	Efficient Air Compressors (VSD) Efficient Air Nozzles No Loss Condensate Drain Compressed Air Leak Repair Rcx_Compressed Air Optimization Efficient Air Compressor Equipment Efficient Air Compressor Controls Process Improvement - Air Compressor		
Cooking	Combination Oven Convection Oven Electric Griddle Electric Steam Cooker	ENERGY STAR Dishwasher Electric Fryer Insulated Holding Cabinets Advanced Cooking	
Cooling	AC - 16 SEER AC - 18 SEER AC - 21 SEER Air Conditioner - 17 IEER Air Conditioner - 18 IEER Air Conditioner - 21 IEER Air Conditioner - 14.3 IEER Air Conditioner - 15 IEER	PTAC AC Tune-up Air Side Economizer Air Cooled Chiller Water Cooled Chiller	HVAC Occupancy Controls Smart Thermostat Window Film Triple Pane Windows Energy Recovery Ventilator
Heating	HP - 16 SEER HP - 18 SEER HP - 21 SEER HP - 15.0 IEER COP 3.6 HP - 16.0 IEER COP 3.8 HP - 14.5 IEER COP 3.5	HP - 15.5 IEER COP 3.7 HP - 12 IEER 3.4 COP HP - 13 IEER 3.6 COP Geothermal HP - 17 EER Geothermal HP - 19 EER	PTHP Garage Door Hinge
Hot Water	Heat Pump Water Heater Low Flow Faucet Aerator Ozone Commercial Laundry Pre-Rinse Spray Valves		
HVAC	Advanced Rooftop Controls Demand Control Ventilation	Retro-commissioning_Bld Optimization Commercial Weatherstripping	

End Use	Measure Types Included		
	High Efficiency DOAS HVAC - Energy Management System GREM Controls	Advanced HVAC Efficient HVAC Equipment Efficient HVAC O&M	
Lighting	Exterior LED Replacing Metal Halide LED Interior Direction LED Linear Lamp LED Troffers LED Linear Ambient Fixture LED Low-Bay Fixture LED High-Bay Fixture	LED Exit Sign Fluorescent Delamping Lighting Occupancy Sensor Lighting Daylight Sensor Dual Occupancy / Daylight Sensor Luminaire-Level Lighting Controls	Networked Lighting Control Advanced Lighting Efficient Lighting Equipment Efficient Lighting O&M Advanced Lighting Controls Efficient Lighting Grow Lighting
Miscellaneous	Non-Refrigerated Vending Machine Controls Kitchen Exhaust Demand Ventilation Control System	High Efficiency Hand Dryers ENERGY STAR Uninterrupted Power Supply Miscellaneous Custom	
Motors	Variable Frequency Drive Controls Power Drive Systems Switch Reluctance Motors Advanced Motors Efficient Machine Drive Equipment Efficient O&M Efficient Motor Pmp Equipment Efficient Motor Pmp O&M		
Plug Loads	Advanced Power Strip – Teri 1 Commercial Use Smart Socket Energy Star Printer/Copier/Fax Energy Star Server Server Virtualization Electrically Commutated Plug Fans in DataCcenters High Efficiency CRAC Unit Computer Room Air Conditioner Economizer Data Center Hot/Cold Aisle Configuration Advanced IT		
Process	Efficient Process Heat Equipment Efficient Process Heat O&M Efficient Process Refrigeration Equipment Efficient Process Refrigeration O&M Process Equipment	Process O&M Process Improvement - Heat Process Improvement - Other Process Improvement - Refrigeration and Cooling	
Refrigeration	Automated Door Closer for Refrigerator Aerofoils for Open Display Cases	Evaporator Fan Motor Controls Strip Curtains Night Covers	Commercial Ice Marker LED Refrigerated Display Case Refrigeration - Custom

End Use	Measure Types Included		
	Automated Door Closer for Freezer ESTAR Refrigerated Vending Machine Refrigerated Vending Machine Controls Door Heater Controls for Cooler Door Heater Controls for Freezer ECM for Evaporator	Evaporator Fan Motor Variable Speed Condenser Fan Display Case Door Retrofit, Medium Temp Floating Head Pressure Controls	RCx Refrigeration Advanced Refrigeration Efficient Refrigeration Refrigeration O&M
Ventilation	VFD Controls Cogged V-Belt (Synchronous) Efficient Ventilation		
Whole Building	Power Distribution Whole Building Retrofit COM Competitions Business Energy Reports Building Benchmarking	Strategic Energy Management BEIMS Building Operator Certification Efficient Dehumidification Efficient HVAC	Mid-Tier IT Improvements High End IT Improvements Hyperscale IT Improvements

5.2.5.2 Achievable Electric Energy Efficiency Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial constraints, customer awareness and willingness-to-participate in programs, technical constraints, and other barriers that the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- MAP estimates achievable potential with NIPSCO paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.

- RAP estimates achievable potential with NIPSCO paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

Residential Sector Achievable Potential

Table 5-10 shows the cumulative annual achievable residential sector energy efficiency potential for the years 2027 to 2046 and estimates of the annual NIPSCO energy efficiency budgets for the residential sector.[124] Cumulative annual residential MWh savings represent 24% and 18% of residential sales in the maximum achievable and realistic achievable potential scenarios, respectively.

Table 5-10: Achievable Residential Sector Annual Energy Efficiency Potential and Annual Utility Budgets

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2027	64,672	19.3	$23,192,756	50,575	12.6	$10,519,160
2028	108,667	35.2	$27,937,935	78,203	20.4	$12,296,863
2029	153,581	51.9	$30,160,372	106,311	28.4	$13,235,799
2030	199,056	69.5	$32,016,573	134,931	36.8	$14,207,522
2031	242,779	84.8	$33,868,763	163,391	44.6	$15,117,341
2032	289,272	101.4	$37,655,268	194,012	53.1	$16,739,498
2033	336,339	119.5	$43,912,595	226,058	62.5	$19,300,726
2034	387,042	137.9	$51,128,069	261,135	72.2	$22,736,831
2035	440,263	157.2	$55,380,771	298,430	82.5	$24,439,390
2036	494,310	177.0	$58,943,898	336,693	93.1	$25,888,556
2037	548,768	196.6	$61,978,625	375,756	103.7	$27,341,096
2038	601,860	215.4	$63,439,508	414,469	114.0	$28,159,380
2039	652,696	232.8	$64,511,729	451,943	123.7	$28,660,711
2040	700,351	248.2	$63,922,935	487,630	132.5	$28,476,395
2041	745,432	262.1	$65,516,656	521,698	140.6	$29,585,240
2042	787,982	274.5	$66,278,332	554,127	148.1	$29,854,785
2043	826,525	285.7	$66,125,283	583,457	154.9	$29,688,014
2044	862,084	296.1	$65,493,837	610,583	161.4	$29,323,415
2045	894,625	305.4	$65,595,063	635,499	167.3	$29,349,148
2046	924,753	313.8	$65,416,740	661,253	173.6	$29,396,758

[124] All achievable potential savings are gross and do not include any adjustments for expected free-ridership and/or spillover.

Table 5-11 below provides the UCT benefit/cost ratios for the period 2027 to 2046 for the residential sector maximum and achievable potential.[125] The overall UCT benefit/cost ratio for the residential portfolio of energy efficiency programs is 2.50 in the realistic achievable potential scenario. In the maximum achievable potential scenario, the overall UCT drops to 1.85.[126]

Table 5-11: Utility Cost Test Benefit/Cost Ratios for Residential Programs

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$984,479,685	$531,699,914	$452,779,771	1.85
RAP	$591,948,901	$236,440,722	$355,508,180	2.50

C&I Achievable Electric Energy Efficiency Savings

Table 5-12 shows the cumulative annual achievable energy efficiency savings for the years 2027 to 2046 and estimates of the annual energy efficiency budgets. Cumulative annual savings by 2046 for the MAP and RAP scenarios represents 24% and 17% of C&I sales, respectively.[127]

Table 5-12: Achievable C&I Sector Energy Efficiency Potential and Annual Budgets

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2027	99,074	16.7	$39,255,766	71,173	11.8	$10,360,372
2028	195,047	32.6	$38,458,634	139,874	23.1	$10,163,890
2029	286,104	47.4	$36,938,615	204,936	33.5	$9,856,851
2030	370,214	60.9	$35,629,196	264,831	43.1	$9,836,659
2031	447,641	73.3	$33,211,602	319,888	51.8	$9,287,855
2032	519,055	84.7	$31,732,504	370,607	59.9	$9,301,386
2033	590,181	97.7	$36,172,390	420,198	68.7	$10,254,498
2034	656,577	110.1	$35,523,645	466,338	77.1	$10,320,037
2035	719,332	122.1	$34,938,435	509,763	85.2	$10,223,970
2036	776,947	133.6	$34,896,361	549,443	92.8	$10,574,611

[125] NIPSCO utilized the UCT as the test for screening measures for inclusion.

[126] Economic screening for cost-effectiveness was performed assuming incentive levels consistent with historical levels.

[127] C&I savings and sales exclude current opt-out customers. All achievable potential savings are gross and do not include any adjustments for expected free-ridership and/or spillover.

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2037	829,601	144.6	$42,166,903	585,941	100.2	$12,393,030
2038	876,710	155.2	$41,210,843	618,703	107.3	$12,075,038
2039	918,659	165.4	$40,549,554	647,698	114.0	$12,227,582
2040	956,320	175.3	$38,618,689	673,627	120.6	$11,653,371
2041	990,757	184.7	$36,911,374	697,366	126.8	$11,515,578
2042	1,011,779	191.9	$44,710,104	712,257	131.7	$14,464,039
2043	1,029,880	198.4	$42,175,314	725,142	136.0	$13,958,534
2044	1,045,370	204.1	$38,682,732	736,200	139.9	$13,039,591
2045	1,058,618	208.9	$36,310,855	745,751	143.2	$12,754,581
2046	1,069,271	212.9	$32,862,096	753,508	146.0	$11,780,106

Table 5-13 shows the NPV of benefits, NPV of costs, net benefits, and the benefit-cost ratio for the C&I sector as a whole, under both the maximum and achievable potential scenarios.

Table 5-13: Utility Cost Test Benefit/Cost Ratios for C&I Programs

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$1,079,823,362	$950,494,866	$129,328,495	1.1
RAP	$716,158,046	$124,077,509	$592,080,537	5.8

5.2.6 DR Potential

Prior to NIPSCO's rate case in 2018, NIPSCO's demand response portfolio comprised load curtailment agreements from a small number of large industrial customers. NIPSCO was responsible for procuring capacity to meet the full peak loads of these customers but also offered a substantial portion of these loads to MISO as LMRs to help satisfy capacity requirements. With the 2018 rate case, NIPSCO must now only procure enough resources for a portion of these customers' loads (known as "firm" loads, approximately 165 MW in total). However, NIPSCO can no longer claim the remaining "non-firm" portion of these customers' loads – nearly 450 MW – as demand response. See above for a description of Rate 531.

Thus, while NIPSCO now has a lower total load obligation than before the 2018 rate case, it also cannot claim any demand response from Rate 531 customers. The change to NIPSCO's demand response portfolio is important to keep in mind when making comparisons to NIPSCO's historical demand response offerings. Like the 2021 MPS and 2022 IRP, the "non-firm" load

associated with Rate 531 customers was excluded from both the demand response potential assessment and NIPSCO's future capacity requirements for the 2024 MPS and the 2025 IRP.

NIPSCO did not have any active DR offerings during 2024 but is in negotiations with vendors to launch two DR offerings in 2025; a Residential Bring Your Own Thermostat program and a C&I Load Curtailment program. The timeline and budgets for these offerings are pending NIPSCO DSM OSB review and regulatory approval.

The DR portion of the MPS considered the following DR program types:

- C&I Load Curtailment
- Data Center Load Curtailment
- Residential Connected Thermostats
- Electric Vehicle Managed Charging
- Residential Time-Varying Rates[128]
- Residential Water Heater Load Control
- Residential Behavioral Demand Response
- Residential Behind-the-Meter Battery Storage

Like the energy efficiency portion of the MPS, the DR portion of the MPS includes two achievable potential scenarios. For each demand response program, the maximum achievable potential represents aggressive assumptions around incentives and program design, which in turn drives higher participation. The realistic achievable potential represents more "middle-ground" assumptions around program incentives and design. Thus, the RAP scenarios generally have lower total demand response potential but are more cost-effective than the MAP scenarios. Each program is also assumed to have a ramp rate, reaching full program capacity after two or three years, which reflects time required to market to and enroll customers in each program. Table 5-14 shows the UCT cost-effectiveness screening results by program based on the MPS avoided cost inputs. To increase optionality in the modeling process, all DR options were included in the DR MPS outputs and considered in the IRP.

Table 5-14: UCT Results by DR Program Type and Scenario

Program	RAP	MAP
Connected Thermostats	Pass	Fail

[128] Includes daily time-of-use, critical peak pricing, and peak time rebates. Enabling AMI is assumed to be in place by 2030, at which time demand response potential savings begin to accrue. AMI costs are not included in demand response program costs.

Water Heaters	Fail	Fail
Behavioral DR	Pass	Pass
Dynamic Rates	Pass	Pass
EV Managed Charging	Fail	Fail
BTM Storage	Fail	Fail
C&I Load Curtailment	Pass	Pass
Data Centers	Pass	Pass

The 2021 MPS and 2022 IRP only considered summer DR potential. Given the transition to a seasonal capacity construct at MISO, the 2024 MPS modeled DR potential separately for the spring, summer, fall, and winter seasons. The summer MAP and RAP demand response by program over the 2027-2046 MPS horizon are shown in Figure 5-1 and Table 5-2, respectively. The difference between aggregate MAP potential and aggregate RAP potential is due to the Connected Thermostat DR offering failing UCT screening under MAP incentive levels.

Figure 5-1: Maximum Achievable DR Potential by Program

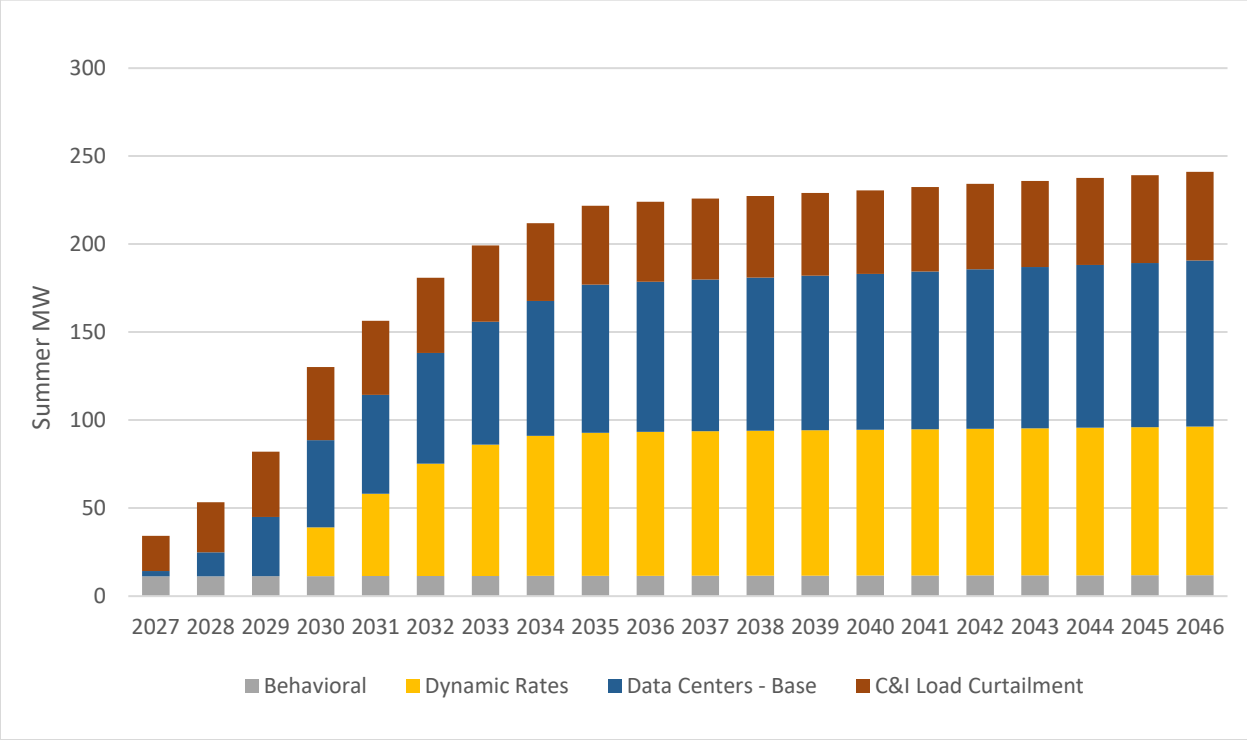
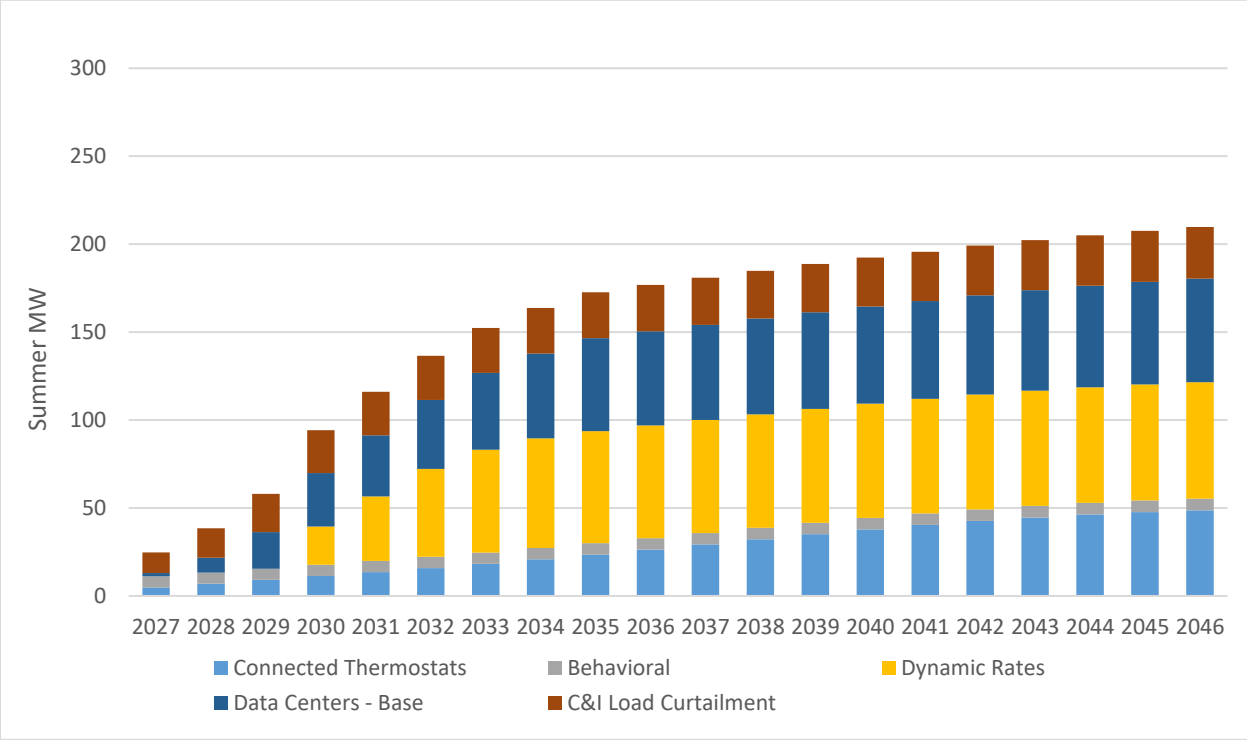


Figure 5-2: Realistic Achievable DR Potential by Program



5.3 Future Resource Options

5.3.1 Energy Efficiency Bundles

For the DSM base case of the IRP analysis, NIPSCO used the realistic achievable potential identified in the MPS as the starting point for developing energy efficiency bundles to be modeled in Aurora.[129] Based on coordination between NIPSCO and the NIPSCO OSB, the GDS Team also developed an Enhanced RAP scenario, which attempted to optimize the cost-effectiveness of the RAP scenario by adjusting incentive levels in certain cases. For both the RAP and Enhanced RAP scenarios, the GDS Team allocated all C&I measures into a single bundle but segmented the residential sector savings into high-cost measures (Tier 2) and low-/mid-cost measures (Tier 1). In addition, the residential sector was further sub-divided into three more bundles, one for behavior measures, due to the unique nature of these types of measures, which have a one-year useful life and have recurring annual costs, and two for income-qualified measures. The first income-qualified bundle (IQW) correlates to measures traditionally offered by NIPSCO, and the second (IQ HEAR) captures savings associated with measures installed by income-qualified customers as a result of participating in federally funded programs associated with the Inflation Reduction Act.[130] The IQW bundle has 10% of the IQ HEAR measure savings and costs allocated toward it,

[129] The realistic achievable potential was selected as the "base case" for purposes of IRP modeling based on the overall cost-effectiveness relative to the maximum achievable potential.

[130] The Inflation Reduction Act established the Home Electrification and Appliance Rebate (HEAR) program, which provides rebates and credits for a variety of measures, including weatherization, HVAC equipment, and heat pump water heaters.

to account for the possibility that NIPSCO will expand its IQW programs in the future to capture some of these savings opportunities. The GDS Team provided the energy efficiency IRP inputs across three different vintage bundles: 2027-2029, 2030-2032, and 2033-2046 to better optimize the value of energy efficiency to the system over different time periods.

In addition, two adjustments to the MPS's realistic achievable energy efficiency potential were necessary, prior to inclusion in the IRP. The first adjustment converted the energy efficiency potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of NIPSCO's programs. Net savings were calculated by applying NIPSCO's most current program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings.

The second adjustment was to provide the achievable potential savings at the generator level. The MPS savings are reported at the meter level. Sector savings were adjusted based on the LLFs noted above, to convert savings from the meter level up to the generator level.

The energy efficiency impacts provided to NIPSCO for IRP modeling, by vintage block, are shown in Table 5-15 through Table 5-17 below, for the RAP scenarios, and Table 5-18 through 5-20, for the Enhanced RAP scenario.[131] The EE MWh impacts for each vintage block provide the cumulative annual lifetime savings. Conversely, because EE program costs are only incurred during the year of measure installation, budgets are only reflected during the identified years in each vintage block. The costs were adjusted to represent program costs minus the NPV of the lifetime avoided T&D benefits from the programs.

In addition to the annual impacts shown in these tables, hourly (or 8,760) shapes that reflect the various measures and end-uses reflected in the achievable potential were provided to NIPSCO to permit the IRP model to assess the value of energy savings on an hourly basis. The 8,760 shapes are unique for each EE sector and vintage bundle.

[131] MW represents the summer impact.

Table 5-15: 2027-2029 Energy Efficiency Base Case Bundles – RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2027	16,362	$3,419,923	2,450	$2,013,267	29,307	$1,669,981	63,372	$7,859,797	1,188	$978,984	977	$860,890
2028	35,071	$3,997,693	5,584	$2,497,028	30,179	$1,757,633	124,647	$7,843,644	2,369	$1,002,121	2,157	$1,048,576
2029	54,055	$4,243,790	8,812	$2,725,808	30,855	$1,836,729	182,724	$7,729,304	3,557	$1,024,847	3,542	$1,240,538
2030	53,571		7,869				177,249		3,527		3,542	
2031	52,524		7,163				170,783		3,527		3,542	
2032	51,994		6,803				162,913		3,514		3,542	
2033	50,254		6,648				159,983		3,500		3,542	
2034	43,721		6,404				155,407		3,487		3,542	
2035	37,338		6,304				152,992		3,487		3,542	
2036	32,269		6,184				148,855		3,487		3,542	
2037	29,166		5,993				135,308		3,452		3,542	
2038	25,539		5,650				120,597		3,417		3,542	
2039	22,327		5,201				106,545		3,382		3,542	
2040	20,981		5,051				102,776		3,382		3,542	
2041	20,482		4,958				101,006		3,382		3,542	
2042	19,951		4,758				65,938		3,339		3,489	
2043	18,399		4,355				33,308		3,180		2,498	
2044	16,629		3,911				3,430		2,998		1,303	
2045	15,427		3,727				3,298		2,845		28	
2046	15,427		3,346				3,298		2,845		28	
2047	13,053		2,366				2,941		2,007		28	
2048	10,208		1,161				2,529		1,172		28	
2049	7,247		240				2,065		342		28	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2050	7,055		161				2,046		342		28	
2051	6,904		86				2,021		342		28	
2052	6,325		17				1,979		341		20	
2053	5,657		17				1,966		340		11	
2054	4,909		17				1,951		339			
2055	4,909		17				1,947		339			
2056	4,909		17				1,945		339			
2057	3,745		13				1,221		225			
2058	1,980		7				565		112			

Table 5-16: 2030-2032 Energy Efficiency Base Case Bundles – RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2030	19,772	$4,164,551	4,370	$3,089,242	31,375	$1,908,955	58,956	$7,898,094	1,235	$1,048,799	1,586	$1,433,374
2031	40,246	$4,366,344	8,768	$3,312,755	31,468	$1,956,740	114,619	$7,555,035	2,462	$1,072,188	3,361	$1,620,830
2032	61,975	$4,818,094	13,314	$3,769,135	31,556	$2,005,334	167,844	$7,753,039	3,702	$1,094,603	5,310	$1,798,357
2033	61,249		11,212				156,804		3,677		5,310	
2034	59,878		9,928				145,470		3,677		5,310	
2035	59,348		9,251				133,955		3,663		5,310	
2036	57,462		9,061				130,873		3,650		5,310	
2037	52,176		8,671				124,151		3,637		5,310	
2038	47,250		8,487				121,756		3,637		5,310	
2039	42,840		8,284				117,492		3,637		5,310	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2040	39,590		7,944				105,266		3,602		5,310	
2041	35,437		7,472				92,026		3,567		5,310	
2042	32,070		6,828				81,055		3,532		5,310	
2043	30,178		6,646				77,795		3,532		5,310	
2044	29,437		6,534				76,627		3,532		5,310	
2045	28,176		6,153				49,658		3,480		5,180	
2046	25,188		5,542				25,567		3,252		3,570	
2047	21,905		4,857				3,167		3,003		1,765	
2048	19,894		4,594				3,021		2,799		36	
2049	19,894		4,183				3,021		2,799		36	
2050	16,953		2,823				2,511		1,974		36	
2051	13,943		1,500				1,960		1,153		36	
2052	10,654		205				1,369		337		36	
2053	10,461		142				1,328		337		36	
2054	10,340		82				1,276		337		36	
2055	9,422		25				1,197		336		25	
2056	8,532		25				1,177		335		13	
2057	7,425		25				1,154		333			
2058	7,425		25				1,146		333			
2059	7,425		25				1,142		333			
2060	5,293		18				669		221			
2061	2,932		10				291		110			

Table 5-17: 2033-2046 Energy Efficiency Base Case Bundles – RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2033	25,337	$5,703,875	7,195	$4,598,831	31,636	$2,054,631	58,890	$8,515,863	1,276	$1,115,749	2,102	$1,963,013
2034	58,815	$7,548,044	14,258	$5,178,993	31,729	$2,106,106	116,719	$8,690,559	2,535	$1,135,403	4,339	$2,112,945
2035	93,473	$8,107,835	20,996	$5,606,652	31,823	$2,158,974	170,172	$8,647,683	3,800	$1,153,441	6,688	$2,246,954
2036	129,121	$8,473,335	27,527	$6,141,943	31,917	$2,213,208	213,572	$8,966,885	5,069	$1,169,784	9,131	$2,364,313
2037	167,230	$8,988,161	34,324	$6,473,824	32,011	$2,268,764	267,182	$10,728,527	6,337	$1,184,423	11,649	$2,465,086
2038	205,591	$9,360,616	40,874	$6,614,348	32,105	$2,325,648	314,251	$10,260,650	7,591	$1,197,464	14,226	$2,550,047
2039	242,397	$9,599,470	47,113	$6,751,402	32,200	$2,384,042	359,084	$10,471,723	8,840	$1,206,911	16,827	$2,601,547
2040	275,017	$9,596,845	52,734	$6,598,125	32,295	$2,443,803	398,734	$9,737,190	10,082	$1,215,646	19,446	$2,645,775
2041	306,575	$10,767,833	57,909	$6,369,654	32,390	$2,504,969	435,324	$9,483,427	11,318	$1,223,793	22,080	$2,683,582
2042	336,259	$10,830,681	62,823	$6,549,695	32,486	$2,567,694	494,814	$13,512,061	12,545	$1,230,332	24,724	$2,716,062
2043	363,647	$10,809,438	66,862	$6,426,694	32,582	$2,632,027	542,194	$12,708,462	13,730	$1,237,440	27,375	$2,744,318
2044	388,456	$10,671,654	70,375	$6,193,093	32,678	$2,697,948	582,919	$11,720,972	14,910	$1,244,243	30,030	$2,769,354
2045	411,467	$10,585,530	73,454	$6,262,606	32,774	$2,765,419	618,172	$11,392,845	16,084	$1,249,937	32,684	$2,784,297
2046	433,531	$10,410,533	76,565	$6,435,549	32,871	$2,834,554	648,599	$10,319,709	17,252	$1,255,696	35,335	$2,799,568
2047	415,177		65,444				603,179		17,179		35,335	
2048	390,026		57,930				532,620		17,065		35,082	
2049	364,554		52,881				469,227		16,730		32,945	
2050	339,648		49,838				419,664		16,381		30,676	
2051	314,845		46,675				374,423		16,019		28,297	
2052	290,383		43,685				335,119		15,662		25,830	
2053	262,820		39,204				297,174		14,485		23,294	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2054	239,478		34,873				264,221		13,309		20,706	
2055	216,692		30,424				233,535		12,137		18,099	
2056	195,659		25,908				207,431		10,969		15,478	
2057	176,610		22,119				158,034		9,844		12,847	
2058	157,613		18,553				113,797		8,723		10,196	
2059	138,289		15,217				73,880		7,609		7,540	
2060	118,711		12,113				38,808		6,503		4,886	
2061	99,845		9,283				7,753		5,404		2,235	
2062	89,307		7,602				6,198		4,409		127	
2063	79,168		6,329				4,644		3,555		113	
2064	68,470		5,136				3,233		2,707		99	
2065	57,690		3,792				1,950		1,865		85	
2066	46,772		2,834				810		1,029		70	
2067	38,235		2,192				611		921		56	
2068	30,266		1,554				412		814		42	
2069	22,927		948				214		708		28	
2070	16,511		459				153		603		14	
2071	10,954		39				92		499			
2072	8,050		29						398			
2073	5,575		20						297			
2074	3,455		12						197			
2075	1,618		6						98			

Table 5-18: 2027-2029 Energy Efficiency Base Case Bundles – Enhanced RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2027	19,868	$5,788,648	2,291	$1,394,054	29,307	$1,669,981	65,417	$12,092,901	1,187	$979,095	977	$860,891
2028	42,897	$6,632,135	4,997	$1,614,881	30,179	$1,757,633	129,111	$12,084,214	2,391	$1,002,291	2,157	$1,048,578
2029	66,471	$6,929,202	7,756	$1,755,827	30,855	$1,836,729	189,592	$11,761,999	3,606	$1,025,072	3,541	$1,240,542
2030	65,866		6,928				184,009		3,526		3,541	
2031	65,104		5,685				177,406		3,520		3,541	
2032	64,893		4,791				169,415		3,507		3,541	
2033	62,862		3,926				166,540		3,494		3,541	
2034	55,366		3,807				162,011		3,480		3,541	
2035	48,039		3,715				159,592		3,480		3,541	
2036	42,722		3,599				155,401		3,480		3,541	
2037	39,239		3,374				141,512		3,445		3,541	
2038	35,213		2,990				126,320		3,410		3,541	
2039	32,093		2,334				111,791		3,375		3,541	
2040	30,934		2,013				107,736		3,375		3,541	
2041	30,584		1,722				105,946		3,375		3,541	
2042	29,905		1,645				69,332		3,332		3,488	
2043	27,832		1,449				35,077		3,173		2,497	
2044	25,444		1,215				3,800		2,991		1,303	
2045	23,705		1,090				3,668		2,838		28	
2046	23,537		1,055				3,668		2,838		28	
2047	19,069		765				3,309		2,001		28	
2048	13,827		510				2,889		1,168		28	
2049	8,603		264				2,412		341		28	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2050	8,412		186				2,394		341		28	
2051	8,260		110				2,369		341		28	
2052	7,544		41				2,328		340		20	
2053	6,670		41				2,315		339		11	
2054	5,695		41				2,299		338			
2055	5,695		41				2,296		338			
2056	5,695		41				2,294		338			
2057	4,339		31				1,522		225			
2058	2,291		16				743		112			

Table 5-19: 2030-2032 Energy Efficiency Base Case Bundles – Enhanced RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2030	24,625	$7,081,671	3,714	$1,955,144	31,375	$1,908,955	61,459	$ 11,615,088	1,310	$1,049,135	1,585	$1,433,381
2031	50,206	$7,261,766	7,265	$2,070,751	31,468	$1,956,740	120,091	$ 11,188,912	2,560	$1,072,614	3,358	$1,620,841
2032	77,550	$7,756,698	10,608	$2,247,118	31,556	$2,005,334	176,061	$ 10,983,642	3,830	$1,094,913	5,305	$1,798,373
2033	76,461		8,804				164,749		3,675		5,305	
2034	75,199		7,065				153,120		3,670		5,305	
2035	74,745		6,107				141,356		3,656		5,305	
2036	72,326		5,349				138,337		3,643		5,305	
2037	66,049		5,106				131,697		3,616		5,305	
2038	60,287		4,936				129,297		3,616		5,305	
2039	55,469		4,739				124,958		3,616		5,305	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2040	51,725		4,345				112,371		3,581		5,305	
2041	47,026		3,837				98,330		3,546		5,305	
2042	43,737		2,946				86,720		3,512		5,305	
2043	42,066		2,590				82,934		3,512		5,305	
2044	41,481		2,287				81,656		3,512		5,305	
2045	40,034		2,054				53,321		3,460		5,176	
2046	36,200		1,650				27,699		3,232		3,566	
2047	31,918		1,194				3,859		2,983		1,763	
2048	29,021		999				3,714		2,780		36	
2049	28,853		934				3,714		2,780		36	
2050	23,540		631				3,186		1,959		36	
2051	18,214		426				2,610		1,144		36	
2052	12,610		240				1,991		335		36	
2053	12,418		178				1,950		335		36	
2054	12,297		117				1,898		335		36	
2055	11,136		60				1,820		334		25	
2056	9,980		60				1,799		332		13	
2057	8,541		60				1,775		331			
2058	8,541		60				1,768		331			
2059	8,541		60				1,763		331			
2060	6,082		43				1,081		220			
2061	3,368		24				488		109			

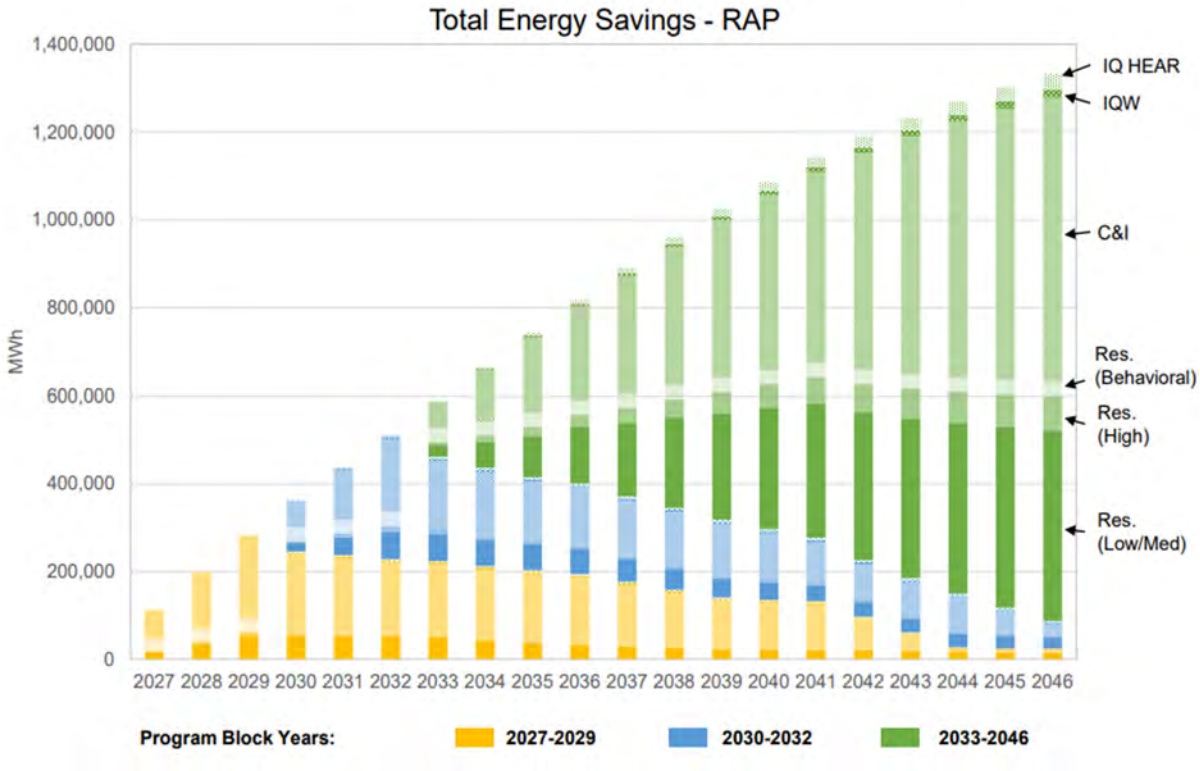
Table 5-20: 2033-2046 Energy Efficiency Base Case Bundles – Enhanced RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2033	31,676	$8,720,124	5,553	$2,719,282	31,636	$2,054,631	62,987	$11,916,407	1,434	$1,116,181	2,099	$1,963,036
2034	72,023	$10,667,326	10,710	$3,082,800	31,729	$2,106,106	123,728	$11,658,184	2,725	$1,135,984	4,332	$2,112,977
2035	113,737	$11,296,524	15,446	$3,372,699	31,823	$2,158,974	179,974	$11,440,014	4,015	$1,154,201	6,676	$2,246,997
2036	156,326	$11,794,105	20,375	$3,756,617	31,917	$2,213,208	225,924	$11,591,134	5,305	$1,170,750	9,112	$2,364,368
2037	201,697	$12,366,923	25,184	$4,219,260	32,011	$2,268,764	282,598	$12,975,460	6,642	$1,182,602	11,622	$2,465,154
2038	246,613	$12,453,276	30,302	$4,559,573	32,105	$2,325,648	333,163	$12,514,244	7,948	$1,195,832	14,190	$2,550,128
2039	288,538	$12,661,045	35,785	$4,999,291	32,200	$2,384,042	381,184	$12,157,896	9,246	$1,205,486	16,781	$2,601,641
2040	325,506	$12,548,387	41,241	$5,229,868	32,295	$2,443,803	424,082	$11,433,519	10,535	$1,214,431	19,390	$2,645,880
2041	360,714	$13,676,630	47,002	$5,500,003	32,390	$2,504,969	463,991	$11,176,659	11,816	$1,222,798	22,012	$2,683,698
2042	392,802	$13,768,017	53,275	$6,066,473	32,486	$2,567,694	527,745	$12,902,636	13,123	$1,227,448	24,643	$2,716,188
2043	421,926	$13,777,318	59,202	$6,373,409	32,582	$2,632,027	579,064	$12,459,673	14,398	$1,234,713	27,281	$2,744,453
2044	447,878	$13,546,326	65,259	$6,578,958	32,678	$2,697,948	622,782	$11,747,953	15,665	$1,241,667	29,923	$2,769,497
2045	471,701	$13,509,422	71,100	$6,889,287	32,774	$2,765,419	660,601	$11,531,846	16,924	$1,247,490	32,562	$2,784,447
2046	494,467	$13,399,619	76,958	$6,984,706	32,871	$2,834,554	693,475	$10,801,640	18,175	$1,253,360	35,199	$2,799,724
2047	472,474		67,682				646,759		17,549		35,199	
2048	443,384		62,233				572,187		17,355		34,946	
2049	413,677		59,104				506,012		16,946		32,813	
2050	386,423		55,945				453,852		16,522		30,548	
2051	359,319		52,453				405,822		16,086		28,174	
2052	332,604		48,962				363,565		15,694		25,714	
2053	300,705		44,961				322,348		14,492		23,186	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2054	273,056		40,939				286,108		13,292		20,607	
2055	246,108		36,544				252,294		12,097		18,010	
2056	221,903		31,741				223,218		10,910		15,400	
2057	200,578		27,191				169,958		9,764		12,782	
2058	179,524		22,243				122,361		8,625		10,143	
2059	158,232		17,112				79,587		7,483		7,501	
2060	137,053		11,723				42,175		6,351		4,860	
2061	116,955		6,180				8,760		5,229		2,222	
2062	102,540		5,445				7,155		4,250		126	
2063	89,784		4,815				5,379		3,424		112	
2064	76,593		4,119				3,778		2,607		98	
2065	63,346		3,507				2,333		1,797		84	
2066	50,276		2,851				1,021		996		70	
2067	40,937		2,207				689		890		56	
2068	32,280		1,569				426		785		42	
2069	24,379		966				221		682		28	
2070	17,522		482				158		580		14	
2071	11,634		68				96		479			
2072	8,485		48						382			
2073	5,831		32						285			
2074	3,587		19						189			
2075	1,668		9						94			

The DSM bundles were incorporated into the IRP as eligible resources in the portfolio optimization analysis and through additional portfolio evaluation discussed later in this report. The DSM bundling approach allows for a representation of potential program duration over time, with differentiation across customer type and costs. Figure 5-3 provides an illustration of the annual expected MWh savings for each energy efficiency bundle under RAP assumptions, along with a summary of the levelized costs. Figure 5-4 provides an illustration of the peak demand savings for each bundle. As shown, the expected savings during the summer peak period for the energy efficiency bundles are considerably greater than those during the winter.

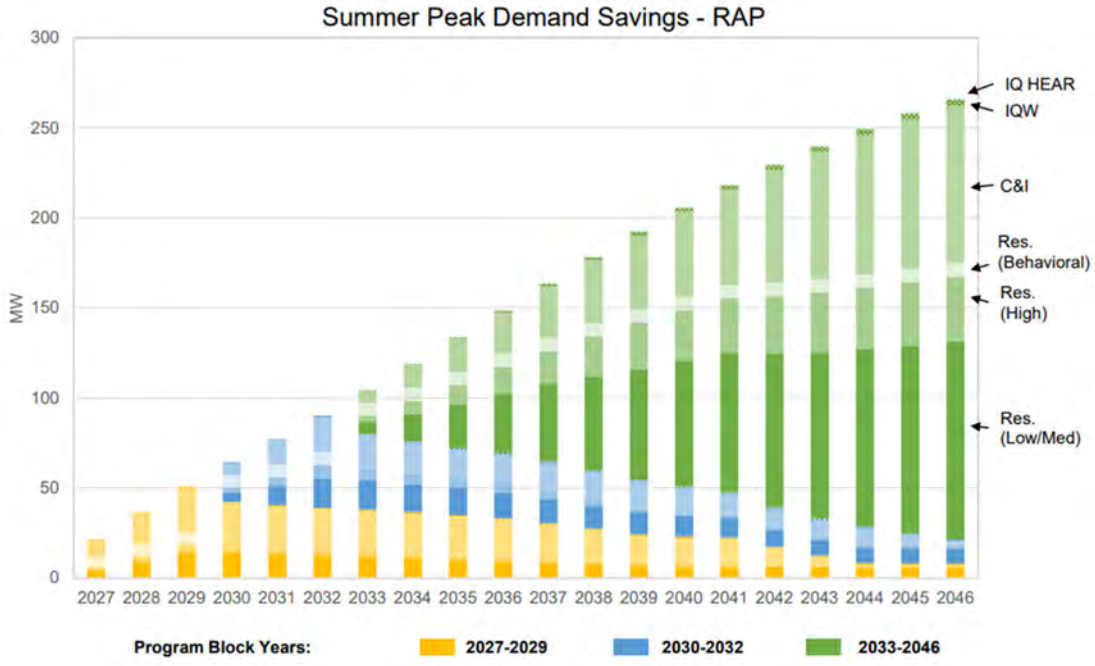
Figure 5-3: Energy Efficiency MWh Savings Bundle Illustration - RAP

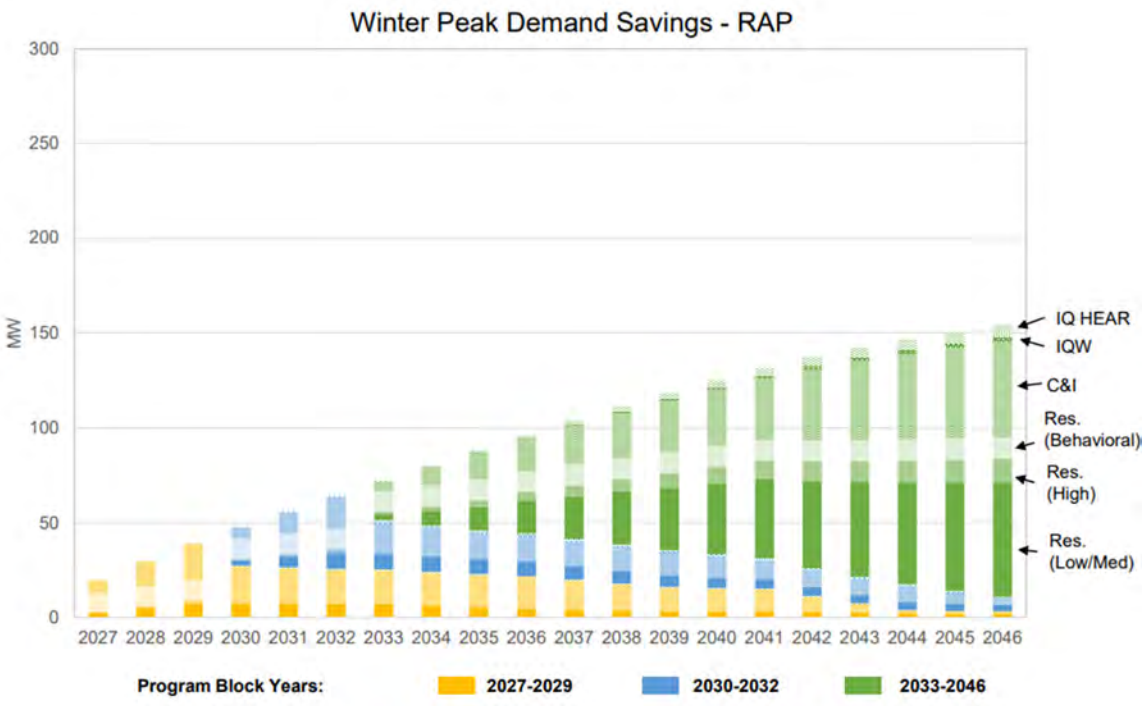


Bundle	Lifetime Levelized Cost ($/MWh)		
	2027-2029	2030-2032	2033-2046
IQ HEAR*	89.09	91.67	99.93
IQW*	77.50	80.02	87.62
C&I	15.81	18.69	22.35
Res. (Behavioral)	58.21	62.13	73.39
Res. (High)	101.51	102.34	106.77
Res. (Low/Med)	26.56	24.95	27.84

**The HEAR bundle is for savings associated with measures allocated towards income qualified customers but which would be offered through a program tied to federal funding rather than a NIPSCO-funded program. The IQ HEAR and IQW savings are "hardcoded" into the IRP modeling.*

Figure 5-4: Energy Efficiency Peak MW Savings Bundle Illustration - RAP





5.3.2 DR Programs

In IRP modeling, NIPSCO considered DR alongside other supply resources to supply capacity and energy needs. To facilitate this effort, the GDS Team provided NIPSCO with annual program potential and costs for the RAP and MAP scenarios for eight program sub-segments. Each DR program type was modeled separately with its own seasonal MW potential and annual cost profile. Avoided transmission and distribution capacity benefits were treated as a reduction in annual DR program cost. The new data center load is assumed to be transmission-connected, so it does not receive the avoided cost of distribution capacity under either avoided cost scenario.

Consistent with the EE IRP inputs, the GDS Team rescreened the demand response program cost-effectiveness under an alternate avoided cost scenario, which assumed a lower cost for avoided generation and a higher cost of transmission and distribution capacity than used in the MPS. This alternate case is meant to reflect the cost of a CT as the proxy unit, instead of a CCGT unit, as in the base case. Under the alternate avoided cost scenario, EV Managed Charging had a UCT ratio greater than 1.0 for both RAP and MAP and the Connected Thermostat MAP scenario passed cost-effectiveness screening. For the C&I Load Curtailment program, the incentive levels, and therefore the enrollment rates, were increased to reflect the higher avoided costs. The result is an increase in the total demand response potential as well as in the overall program costs per kW of capacity.

Table 5-21 provides the DR inputs used in the IRP modeling based on the RAP scenario in the summer season. Table 5-22: shows the MAP program options for the summer season.

Aggregate DR potential is highest in the summer season and lowest in the spring season, largely due to the variation in available loads and the expected timing of system constraints.

Table 5-21: DR Program Options – Summer Potential – RAP

	RAP															
	Connected Thermostats		Water Heaters		Behavioral		Dynamic Rates		EV Managed Charging		Behind the Meter Storage		Data Centers - Base		C&I	
Year	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)
2027	4.85	$242.35	2.30	$1,058.80	6.30	$86.55			0.74	$760.97	0.37	$1,993.83	1.87	$90.41	11.75	$80.29
2028	6.98	$136.34	2.19	$180.55	6.33	$65.01			1.02	$325.62	0.40	$481.28	8.46	$89.71	16.68	$81.13
2029	9.15	$130.41	2.09	$187.37	6.35	$67.34			1.39	$311.72	0.45	$506.15	20.80	$91.58	21.75	$82.91
2030	11.34	$128.03	1.98	$196.59	6.37	$69.75	21.73	$246.81	1.89	$303.02	0.50	$496.21	30.40	$93.87	24.40	$85.49
2031	13.56	$127.61	1.88	$206.84	6.39	$72.23	36.64	$146.23	2.55	$304.79	0.56	$496.38	34.75	$97.44	24.70	$88.48
2032	15.85	$128.57	1.78	$218.53	6.41	$74.79	50.00	$130.66	3.37	$305.58	0.63	$482.47	39.18	$100.99	25.12	$89.59
2033	18.26	$130.41	1.67	$232.03	6.42	$77.45	58.46	$117.82	4.32	$306.19	0.67	$446.27	43.68	$104.57	25.54	$92.50
2034	20.81	$132.85	1.58	$247.85	6.44	$80.20	62.33	$110.15	5.35	$305.95	0.71	$426.09	48.25	$108.16	25.87	$95.42
2035	23.50	$135.72	1.47	$266.68	6.46	$83.06	63.68	$108.08	6.38	$305.76	0.72	$312.37	52.88	$111.75	26.13	$98.35
2036	26.33	$138.84	1.37	$289.23	6.48	$86.02	64.12	$109.81	7.32	$305.01	0.71	$314.71	53.46	$115.36	26.38	$101.26
2037	29.24	$142.14	1.27	$316.41	6.50	$89.08	64.35	$113.19	8.10	$305.47	0.71	$327.15	53.98	$118.96	26.83	$105.34
2038	32.18	$145.60	1.17	$349.23	6.52	$92.23	64.54	$117.11	8.71	$309.07	0.70	$335.49	54.45	$122.56	27.16	$109.41
2039	35.06	$149.18	1.07	$389.10	6.54	$95.49	64.73	$121.24	9.13	$314.19	0.70	$359.19	54.88	$126.17	27.47	$113.48
2040	37.81	$152.86	0.97	$437.70	6.56	$98.86	64.92	$125.52	9.36	$321.72	0.71	$376.62	55.26	$129.77	27.77	$117.51
2041	40.35	$156.69	0.87	$497.38	6.58	$102.33	65.11	$129.92	9.74	$319.40	0.72	$398.68	55.58	$133.38	28.03	$121.53
2042	42.62	$160.72	0.77	$573.99	6.59	$105.91	65.31	$134.48	9.98	$318.26	0.72	$398.28	56.35	$138.18	28.29	$125.53
2043	44.60	$164.98	0.68	$666.58	6.61	$109.63	65.50	$139.20	10.08	$318.24	0.73	$416.73	57.07	$142.98	28.51	$129.52
2044	46.26	$169.48	0.59	$781.26	6.63	$113.46	65.71	$144.14	10.06	$319.21	0.74	$434.91	57.74	$147.79	28.70	$133.50
2045	47.61	$174.22	0.51	$921.58	6.65	$117.41	65.93	$149.17	9.94	$321.39	0.74	$434.53	58.33	$152.59	29.06	$138.63
2046	48.66	$179.23	0.44	$1,098.79	6.67	$121.49	66.15	$154.36	9.87	$336.80	0.75	$448.97	58.86	$157.39	29.42	$143.73

Table 5-22: DR Program Options – Summer Potential - MAP

MAP																
Connected Thermostats		Water Heaters		Behavioral		Dynamic Rates		EV Managed Charging		Behind the Meter Storage		Data Centers - Base		C&I	
DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)
7.29	$427.69	4.61	$924.71	11.21	$78.76			1.31	$308.62	0.75	$2,926.77	2.98	$140.51	20.04	$149.05
11.40	$260.06	4.38	$216.14	11.25	$67.73			1.80	$212.14	0.81	$552.33	13.61	$143.37	28.43	$153.17
15.28	$241.25	4.16	$224.55	11.29	$70.17			2.48	$214.79	0.91	$609.55	33.67	$147.84	37.05	$157.84
18.95	$233.27	3.95	$234.78	11.32	$72.69	27.73	$657.92	3.36	$219.55	1.01	$618.03	49.50	$152.57	41.54	$162.97
22.43	$230.57	3.74	$246.27	11.36	$75.29	46.76	$280.98	4.53	$228.61	1.13	$645.13	56.21	$157.35	42.02	$168.33
25.84	$231.45	3.53	$259.51	11.39	$77.97	63.79	$201.19	5.98	$238.75	1.26	$652.66	62.97	$162.12	42.70	$172.57
29.24	$234.49	3.31	$275.02	11.42	$80.75	74.59	$129.87	7.68	$250.03	1.35	$573.98	69.79	$166.91	43.40	$177.87
32.70	$238.94	3.10	$293.51	11.45	$83.63	79.53	$80.53	9.51	$262.35	1.43	$555.16	76.66	$171.70	44.18	$184.36
36.24	$244.21	2.88	$315.98	11.48	$86.62	81.25	$56.01	11.35	$275.85	1.44	$316.34	84.16	$177.70	44.83	$190.86
39.85	$249.89	2.66	$343.49	11.52	$89.71	81.81	$48.42	13.01	$290.49	1.43	$300.26	85.20	$183.70	45.46	$197.35
43.44	$255.68	2.44	$377.56	11.55	$92.91	82.10	$47.95	14.40	$306.58	1.42	$313.23	86.15	$189.70	46.03	$203.81
46.97	$261.60	2.21	$420.01	11.59	$96.21	82.35	$49.44	15.48	$324.54	1.41	$326.68	87.01	$195.70	46.39	$210.27
50.31	$267.41	1.98	$473.50	11.62	$99.63	82.59	$51.35	16.23	$344.23	1.42	$356.82	87.81	$201.70	46.97	$217.91
53.34	$273.15	1.76	$541.68	11.66	$103.15	82.84	$53.36	16.65	$365.92	1.43	$387.24	88.51	$207.71	47.51	$225.52
55.98	$278.94	1.53	$630.16	11.69	$106.78	83.08	$55.43	17.31	$375.89	1.45	$411.88	89.62	$214.91	47.99	$233.10
58.18	$284.93	1.31	$751.74	11.72	$110.54	83.33	$57.58	17.73	$386.43	1.45	$400.96	90.65	$222.11	48.46	$240.68
59.89	$291.24	1.09	$912.88	11.76	$114.43	83.57	$59.81	17.92	$397.52	1.46	$434.95	91.60	$229.31	48.87	$248.24
61.14	$297.95	0.89	$1,136.24	11.79	$118.44	83.85	$62.40	17.88	$409.16	1.48	$455.99	92.47	$236.52	49.42	$256.97
61.93	$305.03	0.71	$1,452.68	11.83	$122.58	84.12	$64.78	17.67	$421.38	1.49	$457.27	93.23	$243.72	49.93	$265.68
62.30	$312.66	0.54	$1,936.68	11.86	$126.86	84.40	$67.24	17.55	$436.11	1.50	$473.50	94.36	$252.12	50.43	$274.36

The IRP team converted the annual program cost estimate and cumulative DR potential, by season, into a levelized cost by DR program option. The DR programs were then allowed to compete in the broader resource selection process.

5.4 Consistency between IRP and Energy Efficiency Plans

The DSM Statute, which became law on May 6, 2015, requires, among other things, that a utility's EE goals are (1) reasonably achievable; (2) consistent with the utility's IRP, and (3) designed to achieve an optimal balance of energy resources in the utility's service territory. A utility was required to petition the Commission for approval of an energy efficiency plan under the DSM Statute beginning not later than calendar year 2017, and not less than once every three years thereafter.

To remain consistent with the requirements of the DSM Statute, NIPSCO carried out a lengthy analysis of the DSM resources included in its IRP process. As noted above, NIPSCO completed a Market Potential Study in 2024 to determine the achievable amount of savings (*see* Appendix B). NIPSCO, through the MPS process discussed above, conducted an in-depth review of the amount of savings that would be achievable in its service territory with its current customer base. Following that in-depth review process, and as outlined above, NIPSCO incorporated energy efficiency and demand response bundles into the model for selection as resources. NIPSCO allowed the EE and DR, broadly referred to as DSM resources, to be selected across all portfolio concepts that were evaluated in the portfolio analysis phase (*see* Section 9).

In accordance with the DSM Statute, NIPSCO intends to request approval in 2025 of an EE and DR plan, for implementation in 2027, that includes:

- EE and DR goals that are: (1) reasonably achievable; (2) consistent with NIPSCO's 2024 IRP; and (3) designed to achieve an optimal balance of energy resources in its service territory;
- EE and DR programs that are: (1) sponsored by an electricity supplier; and (2) designed to implement EE improvements;
- program budgets;
- program costs that include: (1) direct and indirect costs of EE and DR programs; (2) costs associated with the EM&V of program results; (3) recovery of lost revenues and performance incentives;[132] and
- EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Plan, prior to its filing in 2025, based on the EE and DR selected by the IRP model. This may be updated if another MPS has been completed. The

[132] The "direct costs" are those associated with implementing the programs, including any costs associated with program start up, while "indirect costs" are the NIPSCO administrative costs;

DSM Plan will take into account the results of the IRP for implementation and evaluation of the EE and DR plan.

The benefit of a DSM Plan is that it uses various forms of information, including the IRP, to develop the best strategy for an energy efficiency and demand response plan. The DSM Plan will then be used to develop the DSM RFPs. The results of the winning bids will be utilized to develop the filing, with support from the MPS, IRP, and DSM Action Plan. This is the most effective way to ensure NIPSCO has a DSM plan that is based on real-world, achievable results from vendors who are committed to those results. Bidders' responses to the savings identified in NIPSCO's DSM RFP will vary based on the individual bidder's perception of NIPSCO's customer base and their previous experiences within other service territories, etc. This unique process for the development of the DSM RFPs and the creation of the DSM plan allows NIPSCO to compensate for the long lead time between the completion of a market potential study and the actual implementation of a program.

It is important to note that the final program design is determined by the bidder(s) selected by NIPSCO, with consideration of input from its OSB. The selected bidder's(s') predictions of the market into the program design as they determine what may or may not work in the NIPSCO's service territory is important for designing a DSM program. That means that the programs included in the plan typically change. NIPSCO uses the MPS as a feed into the IRP to develop the Action Plan. This Action Plan allows NIPSCO to take into account not just the results of the IRP, but also the experience of NIPSCO and its vendors with a particular program or measure. For example, electric hot water heating has a great deal of potential, but NIPSCO has not found there to be much interest from customers in the program. Knowing this means that NIPSCO will either (a) not structure a large amount of savings around a measure that has historically shown little participation, or (b) need to increase the incentive to increase participation, which may impact the cost effectiveness of the program.

That does not mean that the DSM plan will be without change. Until the programs are administered to the customer base and the firsthand experiences with energy efficiency and demand response occur, informed judgments must be used to establish the initial estimates of program impacts in NIPSCO's service territory. That is the benefit of utilizing an OSB. It provides an ongoing mechanism to adjust to changing market conditions, including codes and standards and new technologies, and to ensure NIPSCO is capturing as much energy efficiency and demand response savings as possible for the amount of funding available.

Section 6. Transmission and Distribution System

Consistent with the principles set out in Section 1, NIPSCO continues to invest in its existing T&D resources to ensure reliable, compliant, flexible, diverse and affordable service to its customers. NIPSCO continually assesses the current physical T&D system resources for necessary improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at the state, regional, and federal levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. The goals of the planning process include:

- Adequately serve native customer load and maintain continuity of service to customers under various system contingencies;
- Proactively maintain and increase the availability, reliability and efficiency of the electric delivery system; and
- Manage costs while being consistent with the above guidelines

6.1 Transmission System Planning

6.1.1 Transmission System Planning Criteria and Guidelines

NIPSCO Transmission System Planning Criteria requires performance analysis of the transmission system for the outage of various system components including, but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy of transmission system performance is measured in terms of NIPSCO planning voltage criteria, facility thermal ratings, fault interrupting capability, voltage stability, and generator rotor angle stability as documented in the NIPSCO 2024 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix C). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

6.1.2 North American Electric Reliability Corporation

NIPSCO is subject to the NERC, which is certified by the FERC to establish and enforce reliability standards for the bulk electric system and whose mission is to ensure the reliability of the North American bulk electric system. NIPSCO is registered with NERC as a Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Resource Planner, Transmission Owner, Transmission Operator, and Transmission Planner. Together with MISO, in a Coordinated Functional Registration, NIPSCO is registered as a Balancing Authority, Transmission Owner, and Transmission Operator. Each Registered Entity is subject to compliance with applicable NERC standards, and Reliability First Regional Reliability Organization standards approved by FERC. Non-compliance with these standards can result in potential fines or penalties.

6.1.3 Midcontinent Independent System Operator, Inc.

NIPSCO participates in the larger regional transmission reliability planning process through its membership in the MISO, which annually performs a planning analysis of the larger regional transmission system through the MTEP. The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies. It should be noted that any transmission project driven by local factors that NIPSCO needs to build must be submitted to MISO for its planning review to ensure that there is no harm to other systems in the region. Under certain circumstances, NIPSCO can request expedited review of these projects.

NIPSCO is situated on a very significant boundary (seam) between MISO and PJM. As such, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM as defined in the MISO-PJM JOA. In addition, MISO may propose transmission system projects or other upgrades that are not reliability based but are economically based targeted at gains in market efficiency including the lowering of delivered energy costs to the end use customer. These projects must pass the criteria specified in MISO's tariff (including a minimum benefit to cost ratio) before approval.

NIPSCO is also an active participant in MISO and PJM's IMEP processes as defined in the MISO-PJM JOA. The IMEP processes focus on evaluating potential transmission projects to lower the overall production cost and lower delivered energy costs to the end use customer for both of the MISO and PJM footprints. These projects must pass the criteria specified in MISO-PJM JOA (including a minimum combined benefit to cost ratio) before approval.

Requests by generation owners to connect new generators to the NIPSCO transmission system, to change the capacity of existing generators connected to the NIPSCO transmission system, or otherwise modify existing generators connected to the NIPSCO transmission system are handled through the MISO Generation Interconnection Process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests. Requests by generation owners connecting to the PJM transmission system are to be coordinated with NIPSCO by PJM through MISO per the process defined by the MISO-PJM JOA.

Requests by generation owners in the MISO footprint to retire existing generators are handled through the MISO Attachment Y process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify either operating procedures or improvements and upgrades necessary to accommodate these requests. Requests by generation owners in the PJM footprint to retire existing generators may be reviewed by MISO for impacts on the NIPSCO transmission system per the process defined by the MISO-PJM JOA, but the generation owners in the PJM footprint are under no obligation to mitigate any resulting constraints on the NIPSCO transmission system.

Requests by generation owners to secure transmission service are handled through the MISO Transmission Service Request process. NIPSCO participates in this effort to review

potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

6.1.4 Market Participants

MISO has a process through which market participants can request voluntary upgrades on the NIPSCO transmission system to better accommodate generation outlet capacity, reduce congestion, or other market-driven needs. If a market participant wishes to pursue these types of upgrades, they must submit their proposal to MISO and NIPSCO for evaluation in the process defined by the MISO tariff and corresponding Business Practice Manuals. The costs to perform these types of upgrades are negotiated between the market participant and NIPSCO.

6.1.5 Customer Driven Development Projects

NIPSCO may be contacted to undertake transmission upgrades by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts and NIPSCO Economic Development will determine if identified transmission upgrades are necessary to meet the customer's development or expansion plans. Any transmission upgrades identified via this route, that are applicable under the MISO planning processes, are evaluated by MISO to ensure there is "no harm" to any other system in the region as a result of these upgrades.

6.1.6 NIPSCO Transmission System Capital Projects

NIPSCO's current capital project plan for future years as driven by NIPSCO's planning processes and any projects designated and approved through the MISO MTEP planning effort includes:

- Rebuild Marktown 138 kV Substation
- Rebuild Lagrange-Angola 69 kV line
- MISO LRTP-15 (IL-IN Border to Morrison 345 kV)
- MISO LRTP-16 (Morrison to Reynolds to Hiple 345 kV)
- Upgrade Roxanna-Mittal #2 138 kV
- Upgrade Leesburg Substation 138 kV
- New Hiple to Northport 138kV Circuit
- New 138/69kV substation, Menges Ditch, in Elkhart County

In addition to current portfolio, NIPSCO completed the following transmission system projects, including:

- Dune Acres 138kV breaker upgrades
- MISO MTEP20 IMEP Project: Rebuild of the Michigan City to Trail Creek to Bosserman 138kV circuits
- Maple to LNG 138kV circuit rebuild
- LNG to Stillwell 138kV circuit rebuild
- Maple to New Carlisle 138kV circuit rebuild
- Aetna 138 kV Synchronous Condenser

6.1.7 Electric Infrastructure Modernization Plan

The TDSIC plan is an initiative to modernize infrastructure through upgrades to the NIPSCO electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year Electric TDSIC Plan (2016-2022). NIPSCO terminated this 7-Year Electric Plan effective May 31, 2021, and filed a new Electric Plan on June 1, 2021, in Cause No. 45557. In December 2021 this plan was approved by the IURC. NIPSCO's Electric TDSIC Plan, which runs from 2021 through 2026, is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time.

NIPSCO's Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan comprises three main segments: (1) investments that target replacement of aging assets (Aging Infrastructure); (2) investments intended to maintain the reliability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability); and (3) investments to modernize NIPSCO's communications and AMI technologies (Grid Modernization).

6.2 Distribution System Planning

NIPSCO's distribution system is reviewed for local circuit, substation, and source feed adequacy. Normal operating status as well as single element or contingency failure loading and voltage operating characteristics are evaluated along with circuit and system-wide reliability metrics (i.e., CAIDI, SAIDI, SAIFI).[133] Distribution operating and design criteria rely on NIPSCO design thresholds in accordance with Company Standards, Distribution Systems Planning Criteria, and equipment manufacturer ratings. Voltage operating criteria are based on American National Standards Institute (ANSI) C84.1 and Indiana Administrative Code 170 IAC 4-1-20.

[133] CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year.

System improvement plans are developed and applied based upon mitigation of identified deficiencies associated with service capacity, service voltage, reliability levels, and load growth patterns. Specific and trending distribution component failures are mitigated through capital and infrastructure improvement processes. Infrastructure upgrade and replacement activities consider system characteristics including severity of operating deficiencies, likelihood of failure, potential customer impact, current substation and line topology, and equipment age and condition. Available new technologies are integrated into improvement and replacement activities where appropriate.

Net metering is an electricity policy for consumers who own renewable (solar, wind, biomass) energy facilities. Its application provides an incentive for customers to install renewable energy systems and generate electricity to offset their individual usage each month. If a participant produces more electricity than they use on a monthly basis, the customer can receive energy credits at their utility retail rate for their excess generation that can be applied to future usage. The Net Metering program ended for new customer applications for non-residential customers as of October 1, 2021, and for residential customers as of June 20, 2022. The EDG Tariff replaced Net Metering. An EDG credit is applied to a customer's bill if a customer generates more energy than they consume. The EDG credit amount is calculated annually and is 125% of the average wholesale price of power for the prior calendar year.

The renewable feed-in tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources that has helped accelerate the move toward renewable energy sources. The tariff provides power developers with a predictable purchase price for self-generation under a long-term power purchase arrangement, which helps support financing opportunities for these types of projects. The micro solar, micro wind, intermediate wind, and biomass capacity are not fully subscribed, and applications are still being accepted. The intermediate solar category is closed and no longer accepting applications.

NIPSCO implemented its renewable feed-in tariff in July 2011 along with its existing net metering program. These programs helped introduce customer-owned renewable resource based generation onto NIPSCO's electric distribution system. The feed-in tariff program began to attract a significant amount of renewable generation projects which began coming "online" in 2012 and continued to grow. NIPSCO's net metering, feed-in tariff, and EDG tariff generation interconnection programs provide an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's electric distribution systems. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts across the service territory.

By the end of 2023, renewable generation data identified 60.8 MWs of interconnected capacity associated with the net metering program, 36.8 MWs of interconnected capacity associated with the feed-in tariff program and 3.4 MWs of interconnected capacity associated with the EDG program. An aggregate breakdown by renewable fuel type is provided below. These values represent generation resources that include landfill gas combustion engines, animal waste gas combustion engines, photovoltaic solar array farms, small roof-mounted and ground mounted residential solar arrays, intermediate-sized commercial wind turbines, and small commercial and residential wind turbines.

Net Metering Interconnected Capacity:

- 58.6 MWs - Solar Generation
- 1.9 MWs - Wind Generation
- 0.3 MWs - Solar/Wind Combination Generation

Feed-In Tariff Interconnected Capacity:

- 22.3 MWs - Solar Generation
- 0.2 MWs - Wind Generation
- 14.3 MWs - Biomass Generation

EDG Interconnected Capacity:

- 3.4 MWs - Solar Generation

The above biomass related generation value excludes 13.6 MWs of existing landfill based generation interconnected to NIPSCO's distribution system. Although these renewable generation sources feed into NIPSCO's network, the power deliveries are associated with customer PPAs with parties other than NIPSCO. These customers do not participate in NIPSCO's net metering or feed-in tariff programs. In total, approximately 114.6 MWs of generation capacity is interconnected into NIPSCO's distribution system.

6.2.1 Evolving Technologies and System Capabilities

NIPSCO continues the expansion of its distribution SCADA systems, improve its DA systems, and apply other new technologies.

NIPSCO's application of SCADA on distribution substations has undergone expansion, resulting in an increase in coverage from 43% in 2021 to its current level of 53% of all associated stations. Distribution circuit coverage stands at approximately 57% of all circuits. As part of its ongoing infrastructure improvement programs, new, as well as rebuilt distribution substations, and their associated circuits, are assessed for the application of SCADA and DA in their scope and construction. New station projects, as well as full or partial station rebuild projects, are currently being implemented at a rate of approximately five or more per year. Based on continuation of these activities, further expansion of NIPSCO's substation SCADA and DA systems is anticipated to continue.

NIPSCO initiated a new program for technology upgrades on existing control schemes and systems associated with its legacy DA systems. Older system control schemes and equipment are scheduled to be upgraded to new SEL distribution network automation control systems. There were eleven legacy DA systems. Eight out of the eleven will have been upgraded to SEL DA by the end of this year. These new systems feature automatic network reconfiguration and self-healing

actions using algorithms that provide more flexibility and higher levels of reliability. They allow much greater levels of customization of settings and flexibility to fit specific operating conditions. The newer DA automated systems will further enhance how the system determines the best path forward when recognizing faults and restoring customer services. In addition to the above operational improvements, the new systems also provide an opportunity for scaling (expansion) of DA systems that did not exist prior due to previous limitations on the older technologies.

FERC issued Order 2222 in 2020, which is a rule requiring regional grid operators like MISO to allow Distributed Energy Resources to participate in the wholesale markets. NIPSCO has been monitoring how MISO is progressing with its implementation of FERC Order 2222. NIPSCO has been involved in EDC workshop and has attended MISO's DER Task Force meetings. NIPSCO will continue to monitor how FERC Order 2222 progresses and how to comply with the FERC Order.

NIPSCO has experienced some EV charger growth throughout the service territory. Most adopters of EVs are charging at home with level 1 or 2 chargers. To date the loading of Level 1 or 2 EV chargers has not been an issue on NIPSCO's distribution service transformers. If penetration of at home charging increases, it could spur service transformer upgrades. At home charging should be managed, and by increasing visibility and programs it could potentially offset any distribution service transformer upgrade costs. DC fast charging stations can range from 50 to 350 kW per stall, and NIPSCO has seen some locations go up to 2-3 MW of demand. If EV DC fast chargers are placed at every gas station location, it could cause significant distribution system impacts resulting in more infrastructure investment to meet the growing demand of EV DC fast chargers. The current rate of adoption for DC fast chargers has been mild, and we expect that to continue in the coming years until EV cars are widely adopted.

Section 7. Environmental Considerations

7.1 Environmental Sustainability

NIPSCO is committed to delivering energy safely, reliably, and in an environmentally responsible and sustainable way. Since 2005, air emissions, water withdrawal and discharge, and generation of coal ash have significantly reduced. Specifically, as of the end of 2023, NIPSCO had reduced carbon dioxide emissions from electric generation by 76% from 2005 levels. This progress is helping NiSource advance toward its goal of net zero Scope 1 and 2 emissions by 2040.

NIPSCO has invested in environmental control systems across its coal and natural gas generation fleet to comply with environmental requirements while NIPSCO transitions to a more environmentally sustainable generation portfolio. See Table 7-1 for these environmental control systems.

Table 7-1: Environmental Controls on Coal and Natural Gas Generation

Unit	Year In Service	Fuel Source	Particulate Matter (PM) Control	SO_2 Control	NO_x Control	Mercury Control	Coal Ash	Planned Retirement[(1)]
MCGS U12	1974	Coal	Baghouse	Dry FGD	OFA & SCR	ACI & FA	SFC	2028
RMS U16A	1979	Natural Gas	--	--	Water Injection	--	--	2027
RMS U16B	1979	Natural Gas	--	--	Water Injection	--	--	2027
RMS U17	1983	Coal	ESP	Wet FGD	Advanced LNB w/ OFA & SNCR	--	--	2025
RMS U18	1986	Coal	ESP	Wet FGD	Advanced LNB w/ OFA & SNCR	--	--	2025
Sugar Creek	2002	Natural Gas	--	--	SCR	--	--	--

(1) As of November 2024.

ESP = Electrostatic Precipitator
SCR = Selective Catalytic Reduction
ACI = Activated Carbon Injection
FGD = Flue Gas Desulfurization
LNB = Low NOx Burners
FA = Fuel Additives
OFA = Over-Fire Air System
SNCR = Selective Non-Catalytic Reduction
SFC = Submerged Flight Conveyor

7.2 Environmental Compliance Plan Development

NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste, and solid waste that protect health and the environment. NIPSCO is committed to complying with all regulatory requirements. This commitment is embodied in NiSource's Environmental, Health and Safety, Climate Change, and Sustainability Policies and is implemented through a comprehensive environmental management system.

Compliance plans are developed and implemented to meet new and changing environmental policy developments.

7.3 Environmental Regulations

7.3.1 Solid Waste Management

The EPA finalized a rule regulating the management and disposal of CCR which became effective on October 19, 2015. The 2015 CCR Rule regulates CCRs under the RCRA Subtitle D as nonhazardous. The 2015 CCR Rule is implemented in phases establishing requirements related to groundwater monitoring, CCR management and disposal, reporting, recordkeeping, and corrective action.[134] The rule allows NIPSCO to continue its byproduct beneficial use program, significantly reducing CCR that must be disposed.

NIPSCO has completed several projects and has active ongoing projects to comply with the 2015 CCR Rule. Retirement of Schahfer Generating Station Units 17 and 18 by 2025 avoids significant capital cost needed to comply with the 2015 CCR Rule and other environmental requirements.

On May 8, 2024, the EPA finalized changes to the CCR regulations that address inactive surface impoundments at inactive facilities, referred to as legacy impoundments, and CCR management units at inactive and active facilities. This Legacy CCR Rule, which is not expected to impact generation resource planning, requires these newly regulated units to conform to requirements such as groundwater monitoring, closure, and post-closure care.

7.3.2 Clean Water Act and Effluent Limitations Guidelines (ELG)

EPA first promulgated the ELG Rule in 1974, and has amended the regulation many times, with the latest revision effective date of July 8, 2024. The ELG Rule regulates wastewater discharges from power plants operating as utilities. The implementing requirements are incorporated into NPDES permits. Significant capital expenditure is not expected for NIPSCO to comply with the ELG Rule given the expected retirement dates of the coal units at, as well as the dry FGD and CCR-related investments at Michigan City.

7.3.3 Clean Air Act

While several Clean Air Act regulations apply to NIPSCO's operations, including the Cross State Air Pollution Rule and Mercury and Air Toxics Standards, these regulations are not significant drivers of resource considerations in this IRP due to the emission control technologies already installed at NIPSCO's electric generating stations and NIPSCO's plans to retire coal-fired generation. However, as discussed in more detail below, the EPA recently finalized greenhouse gas emissions standards for fossil fuel-fired electric generating units that are examined in this IRP.

134 https://www.nipsco.com/about-us/ccr-rule-compliance-data-information

7.4 Climate-Related Considerations

On May 9, 2024, the EPA published final New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units and Emission Guidelines for Greenhouse Gas (GHG) Emissions From Existing Fossil Fuel-Fired Electric Generating Units. EPA's final rule will not affect NIPSCO's existing generation but is expected to impact other steam generating units. As designed by the EPA, new gas generation would be required to meet certain emission limits based on capacity factor, which could impact needed resources under several of the IRP scenarios. NIPSCO has included the GHG Rule in four of the five IRP scenarios.

Although several legislative and executive actions related to GHG emissions have been promulgated over the last decade, there is currently no federal price on carbon. However, given multi-faceted efforts through the legislative and executive branches to reduce GHG emissions, the AER scenario assumes GHG emissions from the power sector are regulated more heavily. In this AER scenario, NIPSCO has implemented a carbon price curve that limits warming to ~2°C by 2100, based on research by the Brookings Institution.[135] This price curve represents a range of potential future environmental policy options that may impact the cost of emitting carbon, rather than an explicit carbon tax policy. Refer to Section 8 for further discussion of carbon policy and prices.

[135] Hansel et al, "Climate Policy Curves: Linking Policy Choices to Climate Outcomes," Brookings Institution, December 2022.

Section 8. Managing Risk and Uncertainty

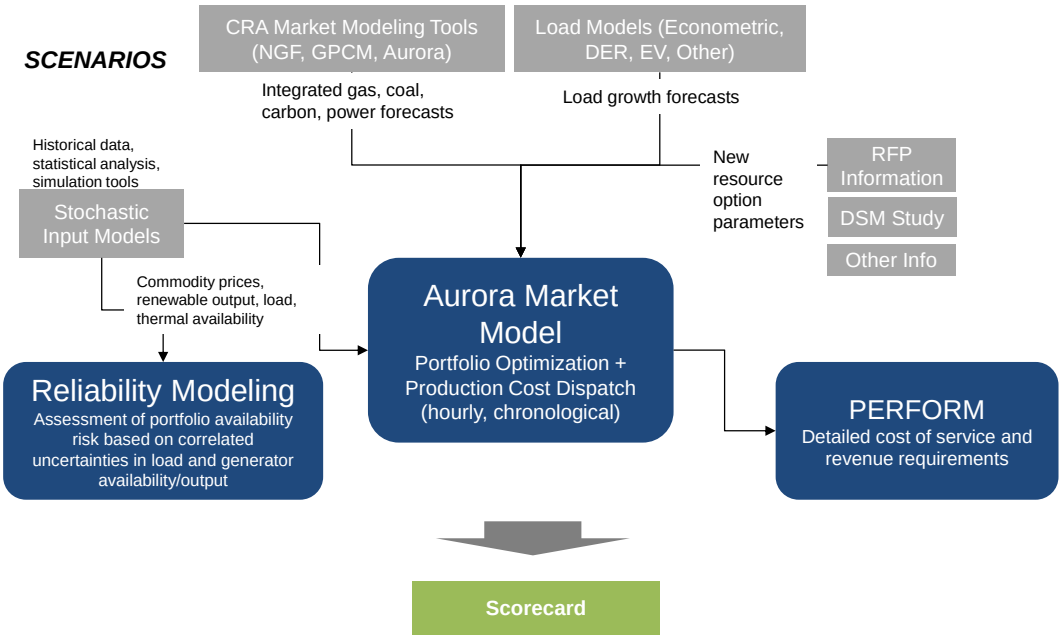
8.1 Introduction & Process Overview

In the 2024 IRP, NIPSCO deployed an approach to evaluating risk and uncertainty that involved the development of a fundamentals-based set of key Reference Case market drivers and the deployment of both scenarios and stochastic analysis to assess uncertainty around this Reference Case. NIPSCO developed the major inputs and associated uncertainty ranges for the 2024 IRP through the following process:

- Development of the Reference Case set of assumptions through fundamental energy sector, commodity price, and load forecasting models;
- Identification of the key drivers of uncertainty and appropriate assignment to scenario or stochastic analysis frameworks;
- Development of distinct scenario themes with accompanying model-based forecast assumptions; and
- Development of stochastic distributions for relevant variables.

The major market assumptions for the Reference Case and the scenarios were developed using a set of fundamental market models deployed by CRA and summarized in Figure 8-1. These models include the NGF model for natural gas price projections, probabilistic input development tools designed by CRA, and the Aurora model for long-term MISO-wide capacity expansion, production cost analysis, and granular power price forecasting. Section 2 has additional detail on the models used in the IRP.

Figure 8-1: Resource Planning Approach and Uncertainty Modeling Tools



8.2 Reference Case Market Drivers and Assumptions

This section provides an overview of the fundamental drivers that underpin the NIPSCO Reference Case for natural gas prices, coal prices, environmental policy including carbon prices, and power market prices.

8.2.1 Natural Gas Prices

Figure 8-2 provides an overview of the key inputs that drive CRA's fundamental forecast of natural gas prices in the NGF model. NIPSCO's 2024 Reference Case natural gas price forecast is driven by several key market assumptions regarding the major supply and demand dynamics in the North American natural gas market. Figure 8-3 summarizes the major supply side drivers, along with CRA's approach and assumptions for each driver, as well as supporting explanations. Figure 8-4 provides the same information for the major demand side drivers. The remainder of this section then provides additional detail related to each driver.

Figure 8-2: Overview of CRA's NGF Model Inputs



Figure 8-3: Supply Side Natural Gas Price Drivers – Reference Case

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee ("PGC") "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2022 "Minimum" resource, and grows the resource base to achieve PGC 2022 "Most Likely" volumes by 2050 to reflect pace of incremental discoveries over time.
Well Productivity	• Initial Production ("IP") rates based on historic drilling data • IP improves as per Energy Information Agency ("EIA") Tier 1 assumptions	CRA bases individual well productivity on historic data analyzed for each producing region; IP rates improve annually, consistent with EIA assumptions.
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA starts from drilling and operating costs reported by major producers in each supply basin; cost improvements over time are based on latest EIA assumptions.
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	CRA uses EIA's forecast of domestic oil prices and production; this includes the impact of oil production and environmental regulations associated with flaring.

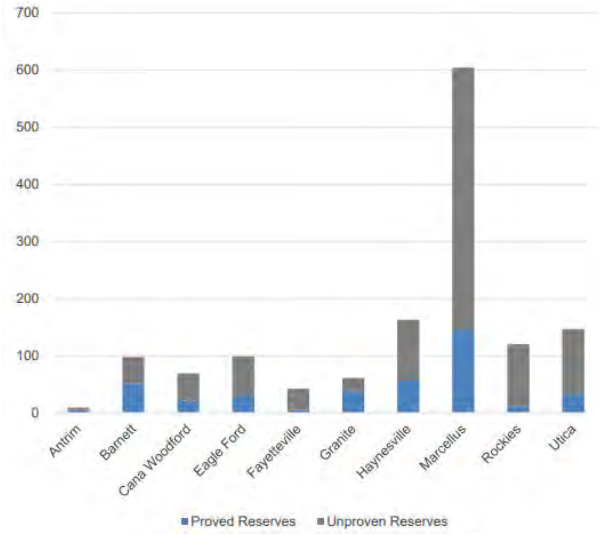
Figure 8-4: Demand Side Natural Gas Price Drivers – Reference Case

Driver	CRA Approach	Explanation
Domestic Demand	• CRA electric power sector simulation • Other sector natural gas demand synthesized from EIA	CRA expects natural gas domestic demand to be relatively stable to slightly declining under the Reference Case, with power sector declines driving the biggest long-term change.
LNG Exports	• Based on review of proposed projects • General uptick in under-construction projects completed and total exports	CRA expects no further export capacity beyond projects that are already operating or which have already achieved Final Investment Decision and are under construction, due to increased competition from suppliers with lower production costs or located closer to demand centers. However, existing and new facilities also have the potential to operate at higher utilization rates over time.
Pipeline Exports	• EIA predictions for net imports	CRA expects modest growth in pipeline exports to Mexico as well as decreasing imports from Canada.

8.2.1.1 Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on a weighted average between the PGC 2022[136] "minimum" and "most likely" estimates as the value of unproven shale reserves. "Minimum" corresponds to a 100% probability that the resource is recoverable, while "most likely" refers to what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions. On the other hand, the amount of proven reserves was taken from EIA's "Annual Report of Domestic Oil and Gas Reserves". The assumed available reserve estimates by basin are shown in Figure 8-5.

Figure 8-5: Available Shale Reserves by Basin

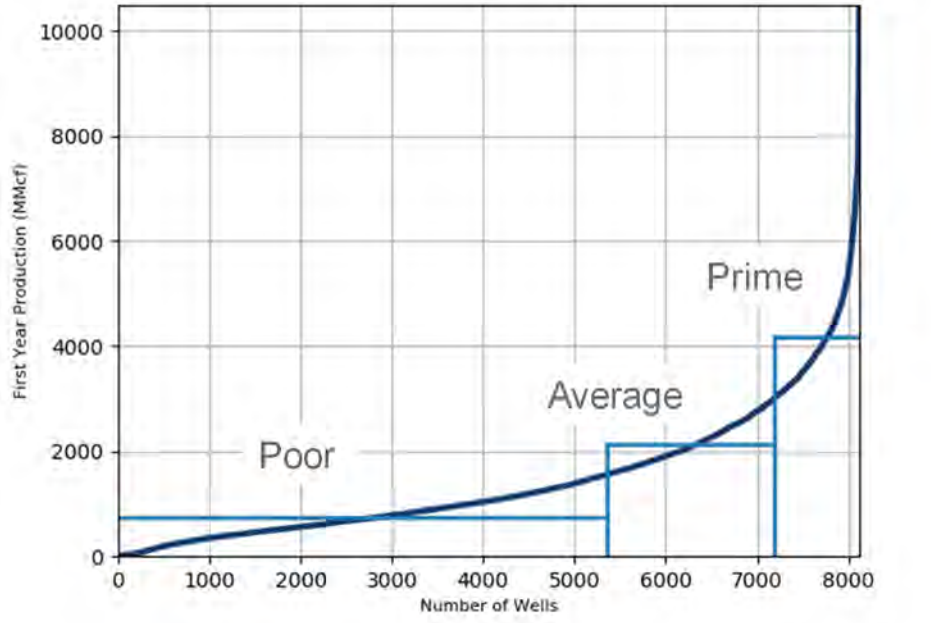


136 Note that the PGC 2022 view was released in July 2023, with PGC 2024 not available at the time of the development of NIPSCO's 2024 IRP assumptions. Scenario development (discussed further below) incorporates a range of views on the future resource base, anticipating potential ranges of resource base in the PGC 2022 report.

8.2.1.2 Well Productivity

Natural gas well productivity assumptions are important drivers of ultimate production efficiency, especially since the bulk of the natural gas resource is currently unproven, meaning that the geology of that resource is currently unknown. In developing assumptions for this variable, CRA generated productivity distributions for each production basin based on drilling data in regions that producers expected to have favorable geology. CRA's view is that historical data has a bias toward higher producing sub-regions, since the wells that are completed and ultimately produce gas do not reflect a random sampling of the underlying geology in each basin. Therefore, to reflect the expectation that the remaining resource is more likely to be lower quality over time as the premium acreage is depleted, CRA assumes a "Poor Heavy" productivity distribution for future undiscovered resource in the Reference Case. An example of this distribution for the Appalachian region is shown in Figure 8-6, with the number of wells shown on the x-axis and the level of first-year production shown on the y-axis.[137]

Figure 8-6: Well Productivity Distribution Illustration for Appalachia



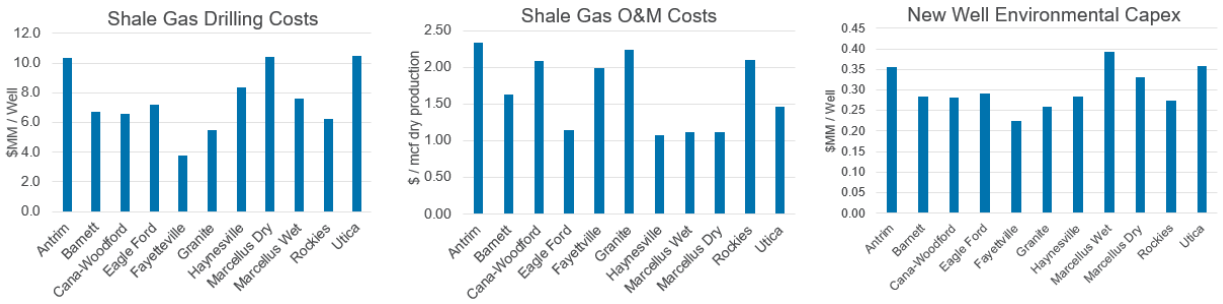
Well Costs

CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region. Producers reported improvements in drilling and O&M costs across most shale basins, and CRA broadly assumes that these improvements will continue over time, largely due to technological innovation, such as advances in machine learning. Figure 8-7 summarizes current drilling costs, O&M costs, and environmental Capex in the major production regions.

[137] Distribution is based on CRA analysis of the Lasserdata drilling database. This proprietary database is produced by Lasser, Inc. and includes historical monthly oil and gas production data.

For going forward costs, CRA relies on the EIA's AEO, as well as documentation from publicly traded drilling companies as well as projections for improvements in drilling and O&M costs from S&P Global's UCCI. Drilling costs are expected to increase by 2% per year through 2025 due to inflationary effects on supply chains, followed by a decline rate of 1.5% through 2050, reflecting the aforementioned advances in drilling technology. Equipment and operating costs are expected to decline by 0.5-1% per year.

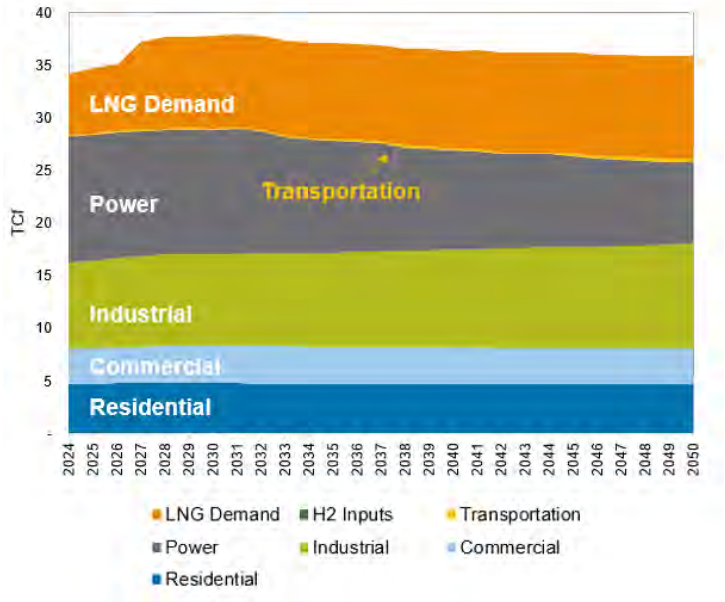
Figure 8-7: Shale Gas Drilling Costs



8.2.1.3 Demand

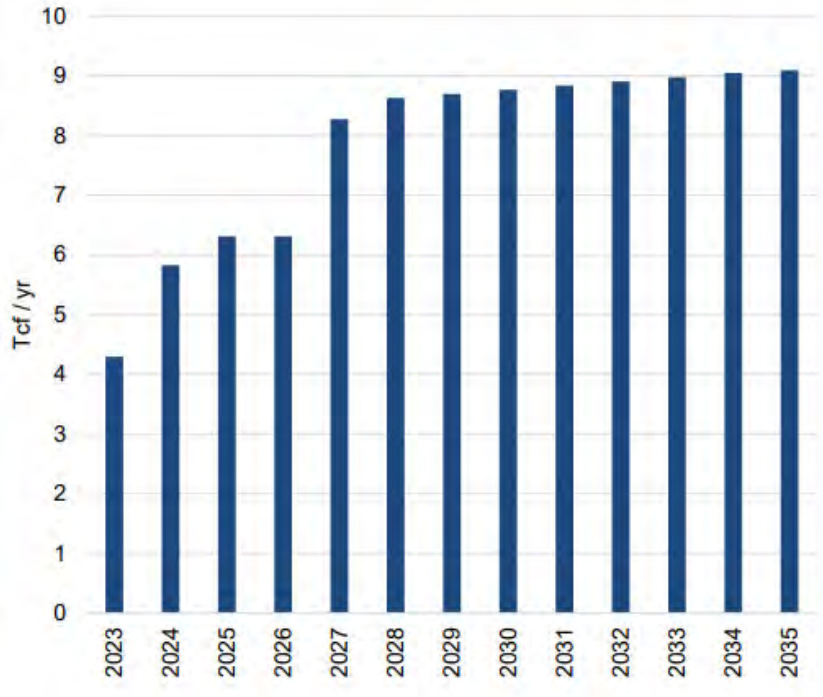
In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for total demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-8 presents the projected domestic demand assumptions through 2050 from the aforementioned sources. Electric sector demand is expected to be relatively flat through the mid-term and then decline in the Reference Case. The AEO's growth expectations for other sectors are also relatively flat, with some positive growth expected in the industrial sector.

Figure 8-8: Natural Gas Demand Assumptions – Reference Case



CRA develops estimates for LNG demand based on a review of existing and proposed export projects. An increase in LNG demand is expected through 2027 and 2028 as several new projects enter into service. CRA's Reference Case assumes small increases in LNG terminal utilization factors over the long-term but does not include any projects not currently approved and under construction. The demand from LNG exports included in the Reference Case through 2035 is summarized in Figure 8-9.

Figure 8-9: LNG Export Demand Projections – Reference Case

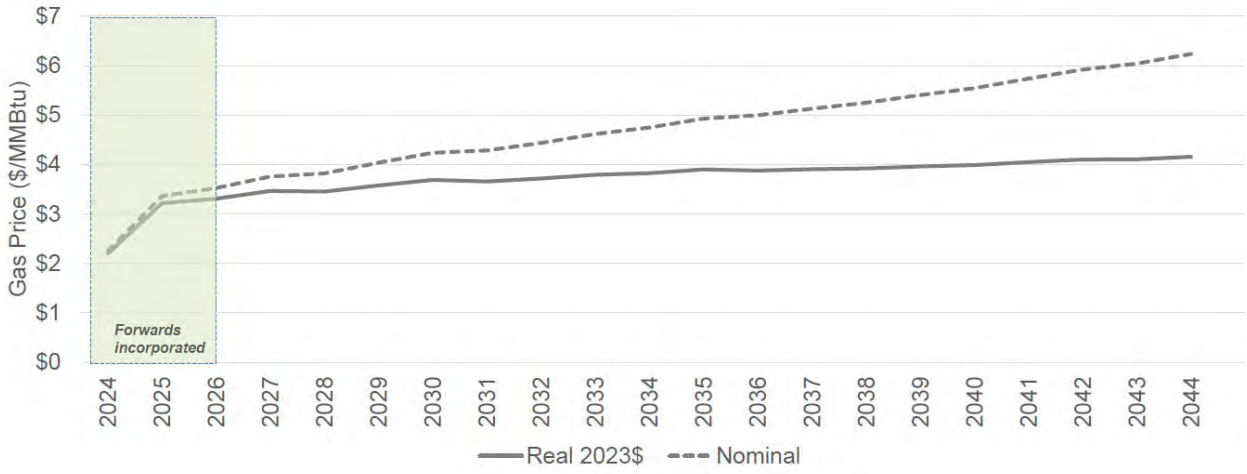


8.2.1.4 Reference Case Price Forecast

CRA's Reference Case price forecast was developed based on each of the supply and demand inputs discussed above and is shown in Figure 8-10. Beyond the forward period, prices are projected to be in the $3.50-$4.00/MMBtu range (real 2023$) for most of the study period. A brief summary of the key drivers of the expectation for increasing prices follows:

- CRA's Reference case view reflects upward pressure in the near term largely as a result of an increase in LNG export demand;
- Modest declines in overall demand resulting from slowing LNG demand growth and declining power sector demand, balanced with both slight increases in marginal production costs and crowding in prime regions leads to a slightly positive trend in real prices from 2035 onward.

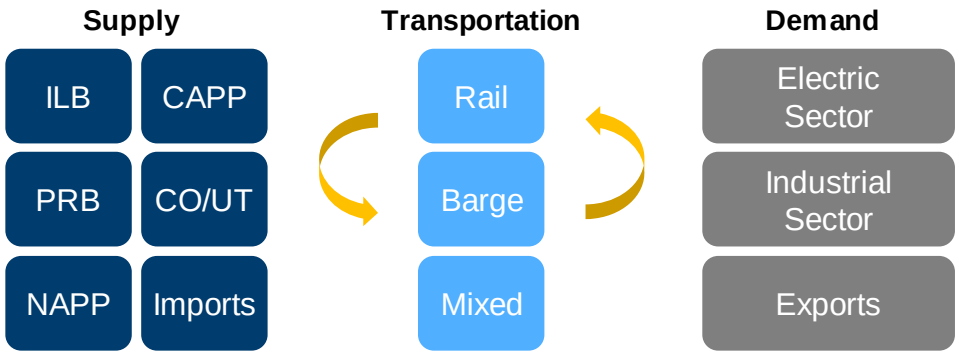
Figure 8-10: Reference Case Gas Price Forecast



8.2.2 Coal Prices

NIPSCO's reliance on coal-fired generation is expected to continue to decline, as Units 17 and 18 at the Schahfer Generating Station are planned to retire in 2025 and Unit 12 at the Michigan City Generating Station (NIPSCO's last coal-fired unit) is planned to retire in 2028. NIPSCO's 2024 Reference Case coal price forecast was driven by a fundamental view of the major supply and demand dynamics for each of the four major coal basins in the United States, integrated with other Reference Case assumptions for natural gas prices (discussed above), carbon policy and prices (discussed below), and the expected evolution of the power sector over time. The core forecasting process incorporates perspectives on coal supply, demand, and transportation to deliver fuel to plants throughout the U.S, as illustrated in Figure 8-11. CRA's process assesses the future supply/demand balance for the U.S. coal market based on macroeconomic drivers, including domestic and international demand, and microeconomic drivers, including trends in mining costs and production.

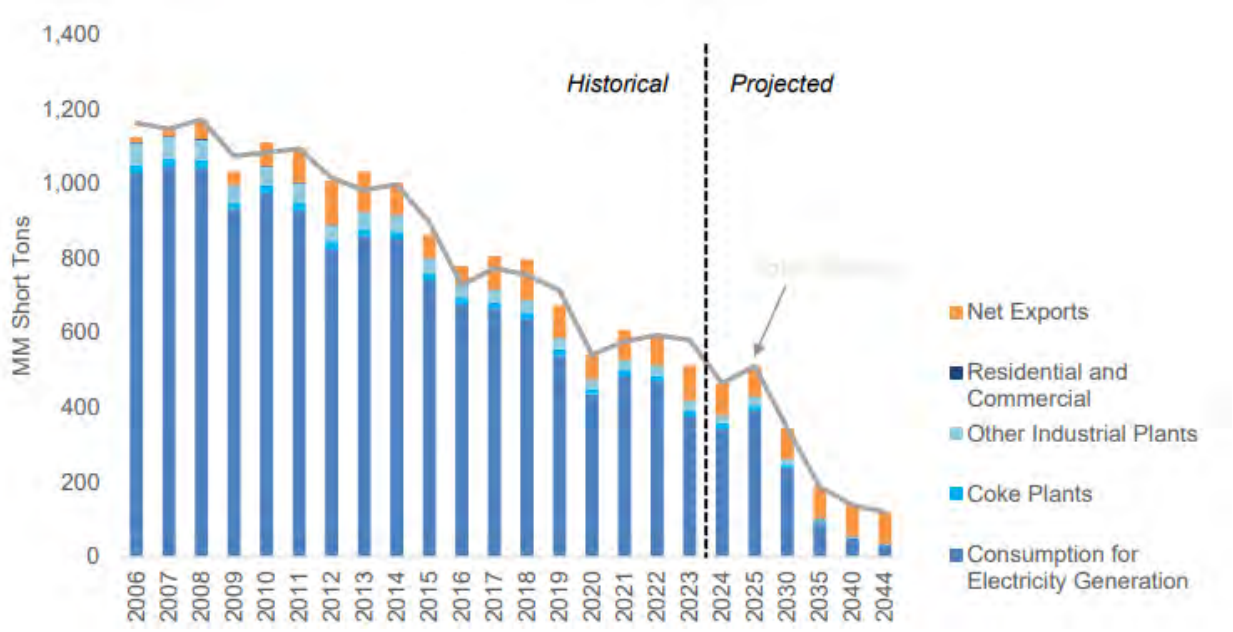
Figure 8-11: Coal Forecasting Process Overview



8.2.2.1 Coal Supply and Demand Trends

Figure 8-12 summarizes historical and projected supply and demand for U.S. coal over the period from 2006 through 2041, which shows that coal demand has generally been in decline over the last fifteen years. Coal retirements have accelerated in recent years, and low natural gas prices have continued to dampen demand, such that total demand for U.S. coal has declined to around 500 million short tons per year, less than half of where it was in 2010. Declines are expected in the next five years, with more substantial declines expected after 2030, particularly as the power sector transitions to other generating resource types.

Figure 8-12: Supply-Demand Balance for U.S. Coal – 2006-2041[138]

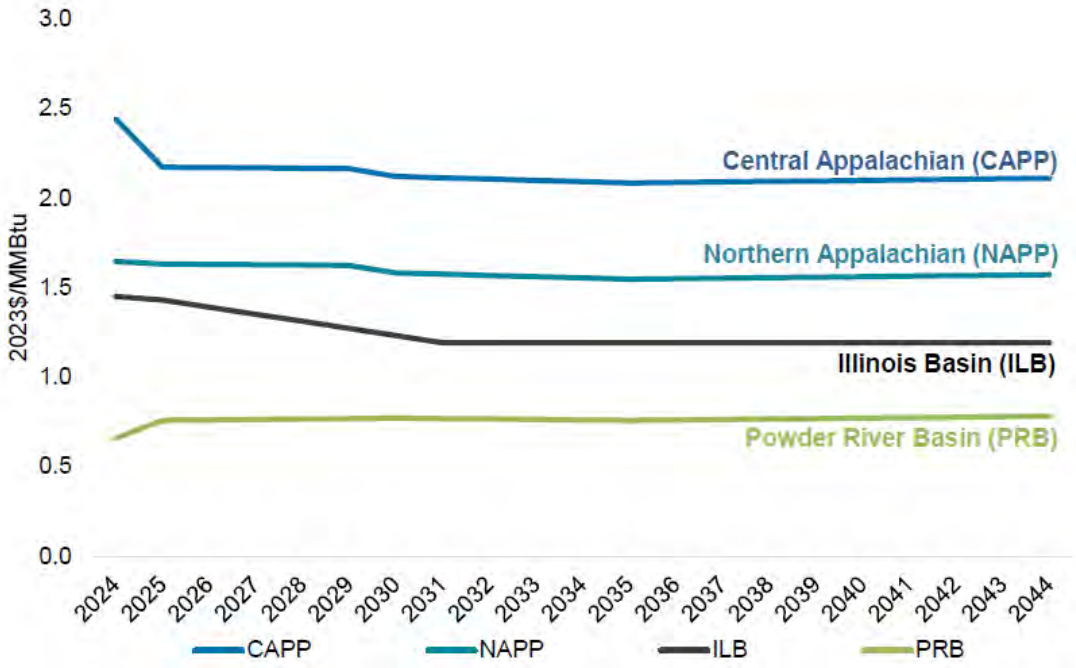


8.2.2.2 Reference Case Price Forecast

CRA's Reference Case price forecast is driven by both the regional production outlook and an assessment of production costs at various demand levels. Figure 8-13 presents the Reference Case price outlook by coal supply region. Overall, spot prices for U.S. steam coal have continued to decline since last year, and over the long-term, coal prices are expected to be flat to declining due to falling domestic demand as a result of the ongoing energy transition in the power sector. Demand for coal exports is also expected to stabilize over the long-term as international markets also decarbonize.

138 2006-2023 data is from EIA and the Mine Safety and Health Administration.

Figure 8-13: Reference Case Coal Price Forecast



8.2.3 Carbon Emission Regulation

Given recent policy and regulatory momentum associated with federal incentives for clean energy resources and regulatory pressures for fossil fuel resources, NIPSCO's Reference Case for the 2024 IRP does not include an explicit price on carbon. However, it does incorporate the GHG Rule for fossil fuel-fired EGUs finalized in April 2024 and published on May 9, 2024.[139] For existing coal-fired EGUs, the final rule establishes subcategories based on expected retirement date:

- Units operating in 2039 and beyond must achieve an emission rate based on CCUS application;
- Units that retire by 2039 must achieve an emission rate based on 40% natural gas co-firing by 2030; and
- Units that plan to retire prior to 2032 have no emission reduction obligations.

For new combustion turbines, the final rule establishes subcategories based on capacity factor:

[139] See EPA fact sheets here: https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-overview.pdf and here: https://www.epa.gov/system/files/documents/2024-04/cps-table-of-all-bser-final-rule-4-24-2024.pdf

- Units operating at a capacity factor greater than 40% must achieve an emission rate consistent with CCUS by 2032;

- Units operating between 20% and 40% capacity factor must achieve an emission rate of 1,170 lbs/MWh; and

- Units operating at a capacity factor below 20% have no effective emission rate limitation if burning natural gas.

In addition to inclusion of the EPA greenhouse gas rules in four out of five of NIPSCO's scenarios, NIPSCO's AER scenario incorporates an implicit price on carbon emissions starting in 2030.

8.2.4 MISO Energy and Capacity Prices

NIPSCO operates within the MISO region, which includes parts of fifteen states throughout the Midwest and South. The traditional MISO North footprint covers parts of Indiana, Michigan, Illinois, Missouri, Kentucky, Iowa, Wisconsin, Minnesota, North Dakota, South Dakota, and Montana, as illustrated in Figure 8-14. Overall, MISO provides the following services to members and participants:

- Oversees markets for energy, capacity (resource adequacy), ancillary services, and transmission rights;

- Maintains load-interchange-generation balance, coordinates reliability, operates or directs the operation of transmission facilities, and oversees transmission planning;

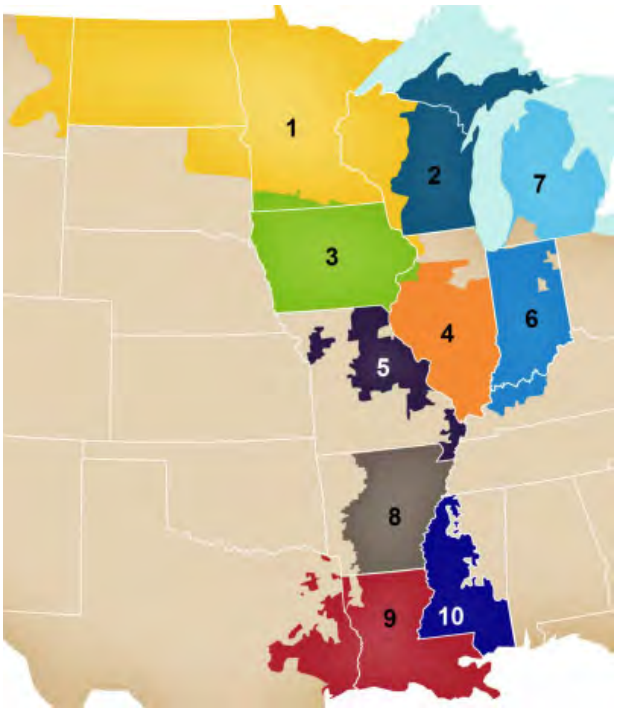
- Coordinates with utilities, states, and federal entities (FERC and NERC) to ensure the reliable, non-discriminatory operation of the bulk power transmission system; and

- Provides an estimated $5 billion in annual benefits[140] to members due to efficient use of power system for resource adequacy and dispatch across a broad geographic territory.

NIPSCO's service territory and resources fall within LRZ6, covering Indiana and parts of Kentucky. In developing the Reference Case market price forecasts for energy and capacity, CRA deployed its Aurora market model to represent the entire MISO footprint and produce fundamental, hourly price projections that are internally consistent with the fundamental outlook for natural gas prices, environmental policy, and the future capacity mix in the region.

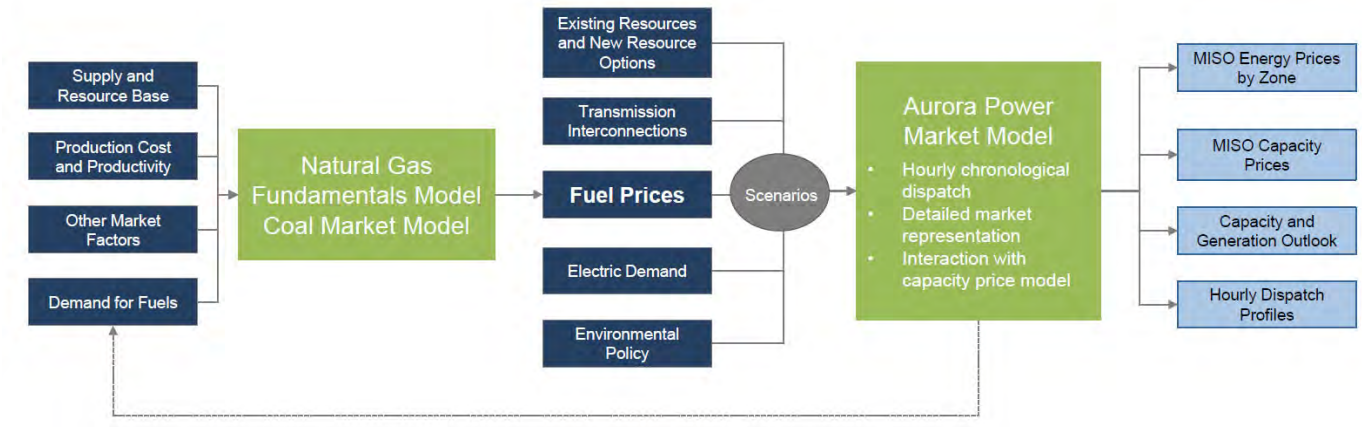
140 See https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

Figure 8-14: MISO Footprint



Based on the market inputs for fuel prices and environmental policy, along with other inputs associated with existing and new resource expectations throughout MISO, regional transmission interconnections, and regional electric demand, CRA developed Reference Case expectations for the MISO market, including energy and capacity prices according to the process shown in Figure 8-15.

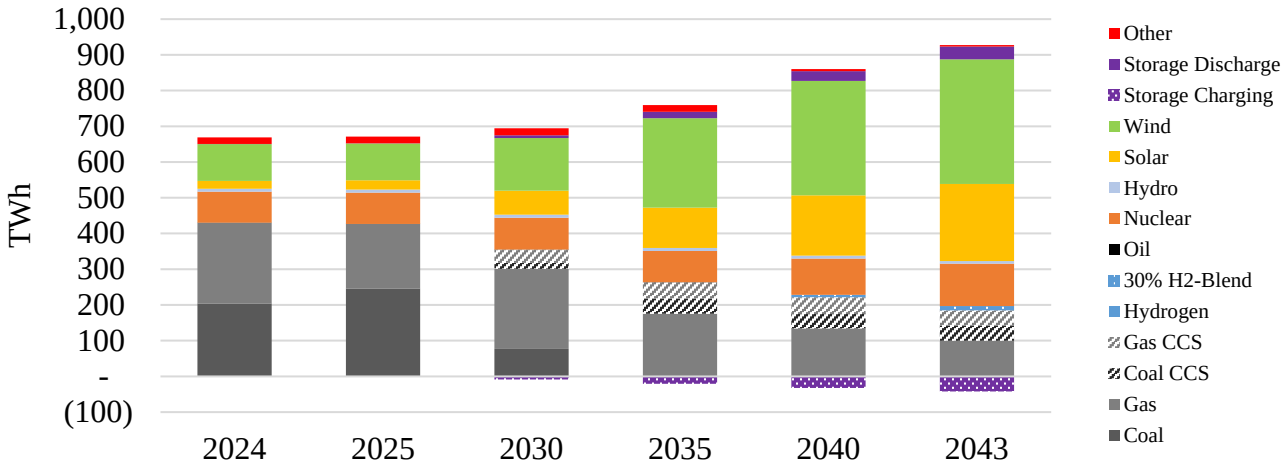
Figure 8-15: Power Market Modeling Process



8.2.4.1 MISO Capacity Mix

CRA's Reference Case analysis expects a continued shift from fossil fuel-fired generating resources towards cleaner energy over the next two decades, particularly in response to the assumed implementation of the EPA GHG rule discussed in the prior section. Since 2015, coal generation has declined from approximately 50% of the total MISO mix to closer to 33%, and the Reference Case forecast projects that it will decline rapidly over the next decade as a result of required retirements or conversions. Meanwhile, the Reference Case expects significant growth in renewable energy from wind and solar, such that by 2043 over 75% of energy generation throughout the region is expected to be from zero-emitting resources, including nuclear. In addition, both coal and natural gas CCUS are expected to grow post-2030. CRA's Reference Case projection of the evolution of the MISO energy mix is presented in Figure 8-16.

Figure 8-16: MISO Generation by Fuel Type –Reference Case Projections



8.2.4.2 Reference Case Energy Price Forecast

CRA's Reference Case MISO energy market price forecast is presented in Figure 8-17 on an annual basis and in Figure 8-18 on a monthly basis. The Reference Case expects that power prices will be relatively flat in real terms in the near-term, due to relatively flat natural gas and coal prices. Longer-term prices are expected to decline slightly in real terms as a result of increased low or zero variable cost generation resources entering the market. Convergence in peak and off-peak prices is projected over time in the Reference Case due largely to growing solar energy output, which tends to reduce peak period pricing.

Figure 8-17: LRZ6 (Indiana) Reference Case Annual Price Projections

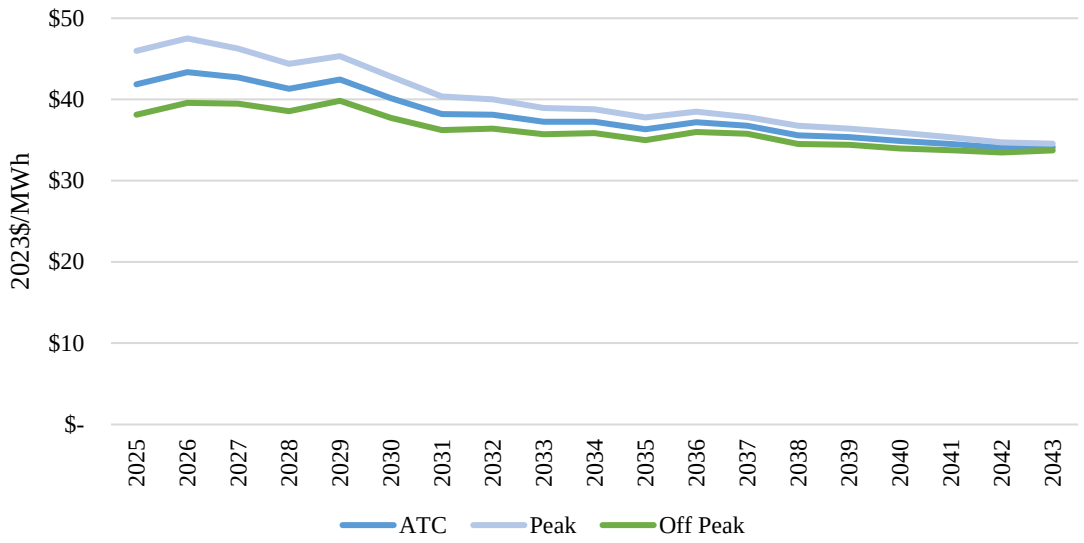
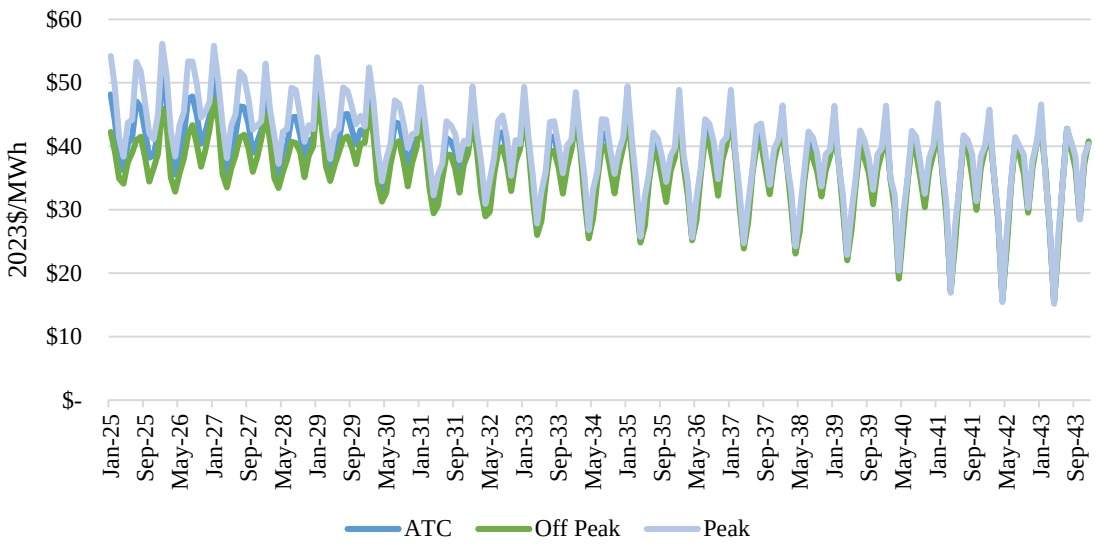
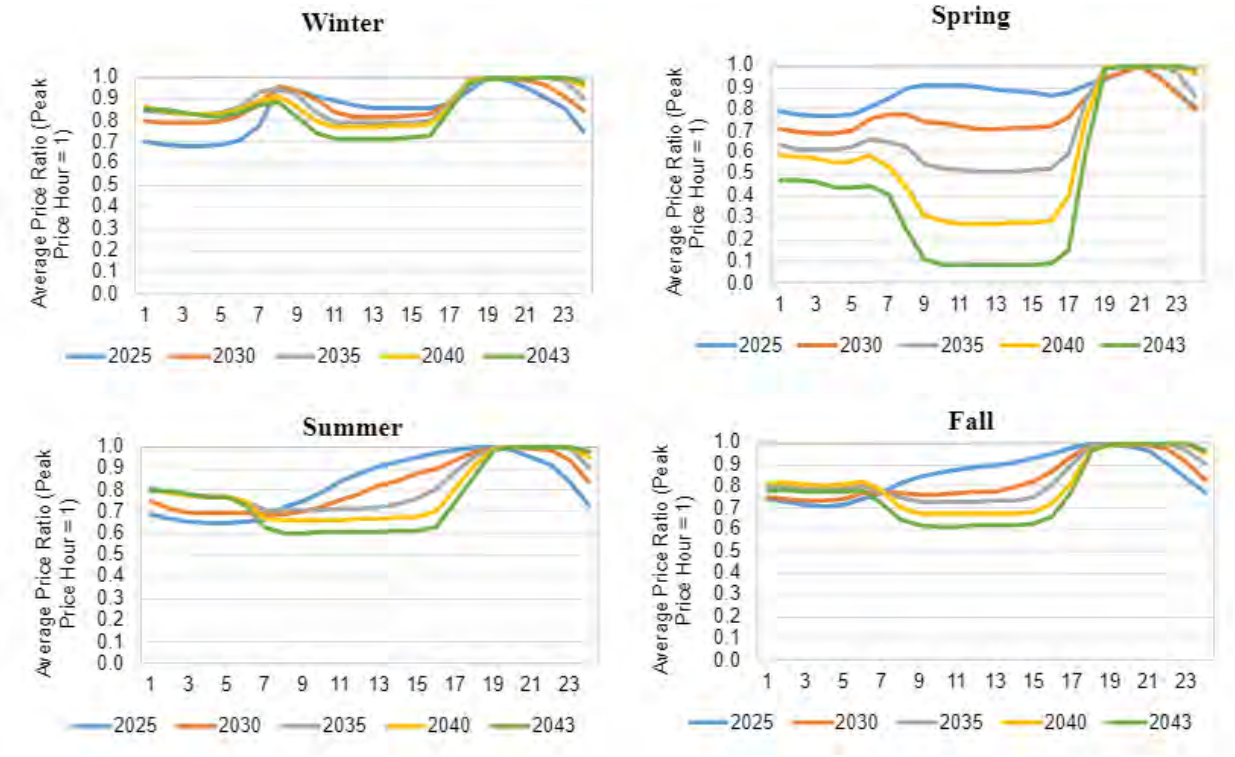


Figure 8-18: LRZ6 (Indiana) Reference Case Monthly Price Projections



Given the expectation for a growing share of intermittent renewable resources in the MISO market over time, hourly price profiles are likely to shift, and CRA's analysis incorporates this phenomenon over time. For example, mid-day prices are expected to decline as a result of solar output, particularly in the spring months when solar output is high, but electric demand is generally low. In addition, the peak price periods during the summer months are expected to shift from late afternoon to evening hours, in line with solar generation patterns. This is illustrated in Figure 8-19.

Figure 8-19: MISO Hourly Energy Price Shape Projections Over Time

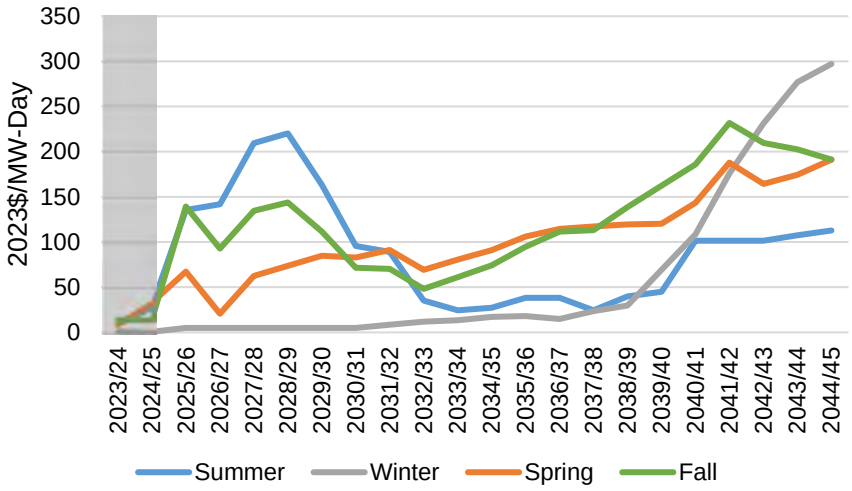


8.2.4.3 Reference Case Capacity Price Forecast

In addition to the energy market, MISO also operates a capacity market which procures capacity in a seasonal auction. The capacity market is based on an administratively set demand requirement and supply offers from market participants that are willing to sell capacity. MISO's first seasonal capacity auction took place in April 2023, followed by the second seasonal auction in April 2024. The 2023/24 auction prices retreated from the price spike observed in the 2022/23 auction, while the 2024/25 auction showed slight upticks in seasonal clearing prices, driven by a combination of higher demand requirements and tighter supply dynamics.

Going forward, CRA expects capacity prices to experience upward pressure over the near term, as the reserve margin throughout the system continues to tighten and MISO's D-LOL rule is implemented. During this period, summer is projected to remain the tightest season. Over the longer-term, the supply-demand balance will likely further tighten as coal resources are replaced by intermittent capacity over time. CRA's price forecast considers expected seasonal resource accreditation trends and demand requirements, and into the 2040s, risks in the winter season are projected to emerge. Figure 8-20 presents the Reference Case capacity price projections over time and by season.

Figure 8-20: Reference Case MISO Capacity Price Projections



8.3 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment

After defining the Reference Case market drivers and conditions, NIPSCO worked to identify the key uncertainties and drivers that could impact future portfolio performance over the long-term. These were grouped into four major categories, including:

- Commodity prices, especially for natural gas and power;
- Environmental policy, particularly regarding carbon pricing, other greenhouse gas emission reduction policies, and federal subsidies and tax credits for specific technologies;
- Load growth, including uncertainty associated with economic growth, EV penetration, DER penetration, electrification, industrial load, and data center load; and
- The future value of intermittent resources associated with capacity credit and hourly generation output.

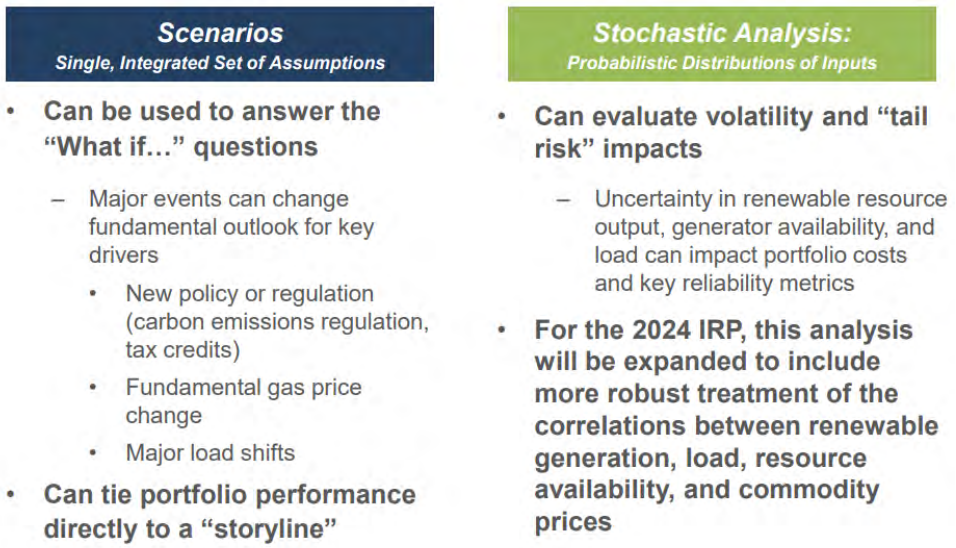
After identifying the major drivers of uncertainty, NIPSCO then assessed whether each would be best addressed through scenario or stochastic analysis.[141] In the 2024 IRP, NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across *both* scenario risk and stochastic risk, since the two complementary approaches can be used to answer different questions and quantify risk in different fashions. Scenarios were structured to assess major changes to specific market driver assumptions, along with related feedback, while stochastic

[141] Scenarios represent future states of the world. Scenario risk represents risk due to lack of knowledge around factors like regional demand growth, environmental policies, structural trends in commodity prices, etc. These sources of uncertainly will reduce with further knowledge as the future evolves. Stochastic risk is driven by randomness which cannot be reduced. Such uncertainties include exact hourly loads, short-term commodity prices, or hour-to-hour and day-to-day renewable generation.

analysis was performed to evaluate more granular volatility and tail risk, largely based on historical data observations. Figure 8-21 provides a summary of the primary purposes and benefits of deploying each approach. In the 2024 IRP, NIPSCO evaluated uncertainty variables in the following fashion:

- Scenario variables:
  - Annual and monthly natural gas prices;
  - Federal carbon policy regulation, including through a carbon price or the EPA power sector GHG Rule;
  - Federal technology incentives, including potential cancellation of production and investment tax credits;
  - Hourly MISO power market prices;
  - NIPSCO and MISO regional load growth, driven by economic factors, EV and DER penetration, electrification initiatives, data center load, and industrial load risk; and
  - Alternative capacity accreditation and obligation requirements across alternative market design concepts and based on MISO market outcomes.
- Stochastic variables:
  - Daily natural gas prices;
  - Hourly MISO power market prices;
  - Hourly NIPSCO load;
  - Hourly renewable generation output for wind and solar resources; and
  - Hourly availability from thermal generators.

Figure 8-21: Scenario and Stochastic Uncertainty Approaches

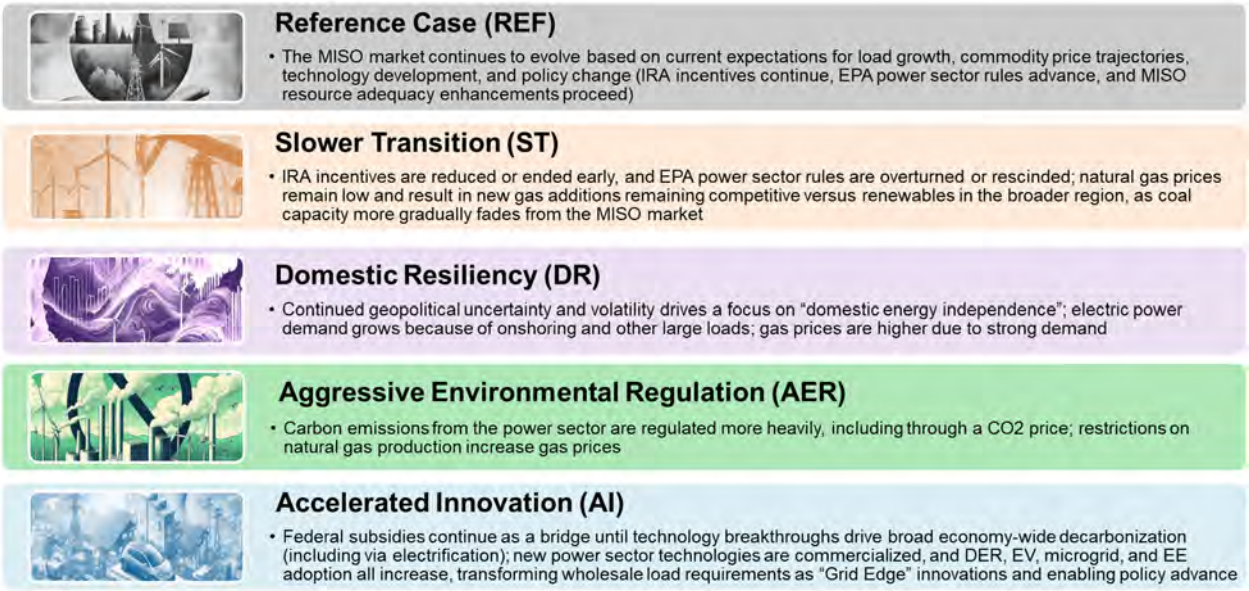


8.4 IRP Scenarios

8.4.1 Scenario Overview

In the scenario development process, NIPSCO developed narratives to describe possible futures, which were organized around "themes" or "states-of-the-world." The first step in developing the scenario themes was to construct assumptions for key macro drivers, which would ultimately translate into changes for the more detailed drivers impacting NIPSCO's portfolio costs. Ultimately, NIPSCO developed four scenarios to supplement the Reference Case, relying on the foundation that was built in its 2016, 2018, and 2021 IRP processes. The 2024 IRP Reference Case incorporates recent market and regulatory trends and positions a baseline outlook against which alternative scenarios were developed. A summary of the scenario themes is shown in Figure 8-22.

Figure 8-22: Scenario Theme Overview



NIPSCO then assessed the themes for diversity and robustness and translated the scenario themes into specific assumptions for the key inputs of commodity prices, carbon policy, technology costs, electric demand or load growth, and market design considerations. Figure 8-23 summarizes the directional movement of the key input assumptions relative to the Reference Case, while the subsequent sections of this Section outline the detailed inputs that were developed for each scenario.[142]

[142] Note that CRA's fundamental MISO market modeling process develops unique MISO market outcomes for each scenario based on the fundamental inputs outlined in the table. Therefore, MISO power market prices are not explicitly noted as input assumptions. Note also that NIPSCO-specific portfolio analysis (discussed further in Section 9) incorporates additional information regarding NIPSCO-specific technology costs for new resources (largely informed by the RFP results summarized in Section 4) and NIPSCO-specific load uncertainties (summarized in Section 3).

Figure 8-23: Summary of Major Scenario Parameters

Scenario	Commodity Prices	Carbon Policies	Technology Costs	Demand	Market Design
Reference Scenario (REF)	Baseline	Current Policy, including EPA power sector CO2 emission rules	Baseline	Baseline	Examine alternative capacity accreditation and obligation requirements across alternative market design concepts and based on MISO market outcomes
Slower Transition (ST)	Low gas price due to abundant resource ↓	IRA pull-back and withdrawn EPA power sector rules ↓	Slower decline for new tech costs; stable IC costs ↑	Low DER and EV	
Domestic Resiliency (DR)	Higher gas price due to strong demand ↑	Current policy, including EPA power sector CO2 emission rules –	Higher due to supply chain constraints, onshoring ↑	New large loads (data centers, industrial onshoring)	
Aggressive Environ. Regulation (AER)	Highest gas price due to production restrictions ↑	EPA power sector CO2 emission rules *plus* carbon price ↑	Baseline –	Higher DER and EV; some electrification	
Accelerated Innovation (AI)	Lower gas price due to demand erosion ↓	Current policy, including EPA power sector CO2 emission rules –	New tech. advancement and decline in costs; IC cost pressures ↓	High EV and electrification plus new large loads; higher DER	

8.4.2 Slower Transition Scenario

8.4.2.1 Summary Description

The ST scenario represents a future with persistently low natural gas prices, a pull-back of tax credits authorized via the IRA, and withdrawal of the EPA GHG Rule. The scenario addresses the combined risks of low commodity prices for natural gas and power and a roll-back of federal incentives and regulations which incentivize a transition away from fossil-fuel fired generation. Given the large amount of uncertainty related to long-term implementation of the EPA GHG Rule, the scenario specifically develops a future where carbon emissions are not restricted while conventional fuel prices remain low, testing the robustness of portfolios against this important risk.

8.4.2.2 Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the ST scenario's price trajectory. Overall, lower prices are realized through the following assumptions:

- Larger resource size: The ST scenario assumes a higher weighting in available unproven resources towards the PGC's maximum trajectory as opposed to its "most likely."
- Higher well productivity: Improvements in well productivity are assumed to be realized more quickly in this scenario.

Figure 8-24 summarizes the major natural gas price drivers for the ST scenario relative to those in the Reference Case.

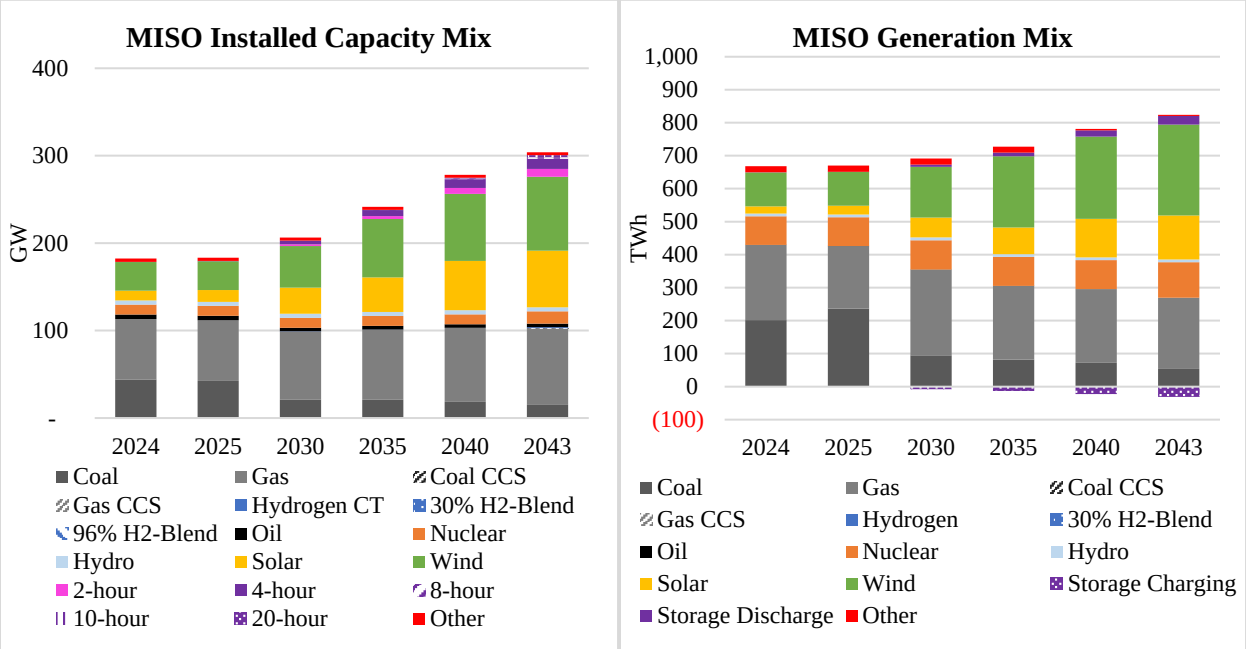
Figure 8-24: Summary of Natural Gas Price Drivers for ST Scenario

Driver	Reference Case	ST
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Unproven resource base assumed higher 
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Accelerated improvement in well productivity 
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Base View 
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Base View 

8.4.2.3 MISO Power Market Dynamics

In the ST scenario, load growth is expected to be slightly lower than in the Reference Case, largely due to slower electric vehicle growth. In addition, the MISO market is expected to transition more slowly away from fossil-fired resources and more gradually towards renewables as a result of lower natural gas prices, withdrawal of the EPA GHG Rule, and an early phase-out of clean energy tax credits from the IRA. While the Reference Case expects over 75% of all energy in MISO to come from zero-emitting resources by 2043, the ST scenario expects closer to 60-65% of total energy produced to be zero-emitting by the same period. Meanwhile, natural gas and coal generation are projected to retain an energy share close to 40% by 2043, with most fossil-fired energy produced by natural gas. Unlike the Reference Case, the ST scenario does not expect deployment of CCUS for coal and natural gas capacity. The projected MISO installed capacity mix and generation mix over time for the ST scenario are illustrated in Figure 8-25.

Figure 8-25: MISO Power Market Evolution for ST Scenario



8.4.3 Domestic Resiliency Scenario

8.4.3.1 Summary Description

The DR Scenario represents a future in which continued geopolitical uncertainty and volatility drive a focus on domestic energy independence, while electric power demand grows significantly as a result of manufacturing onshoring and the emergence of other large loads like data centers. In addition, this scenario assumes gas prices are higher due to strong demand and technology costs decline more slowly due to supply chain constraints and high demand. Overall, the scenario addresses the risk of high load growth, higher technology costs, and high fuel costs.

8.4.3.2 Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the DR Scenario's price trajectory. Overall, higher prices are realized primarily through expected increases in demand for natural gas. Specifically, instead of using AEO's base view for domestic gas demand, a higher trajectory, representing an approximate five tcf annual increase by the end of the study period, was used. This demand growth is expected to come from both the power sector (as a result of additional electric demand) and the industrial sector. Figure 8-26 summarizes the major natural gas price drivers for the DR scenario relative to those in the Reference Case.

Figure 8-26: Summary of Natural Gas Price Drivers for DR Scenario

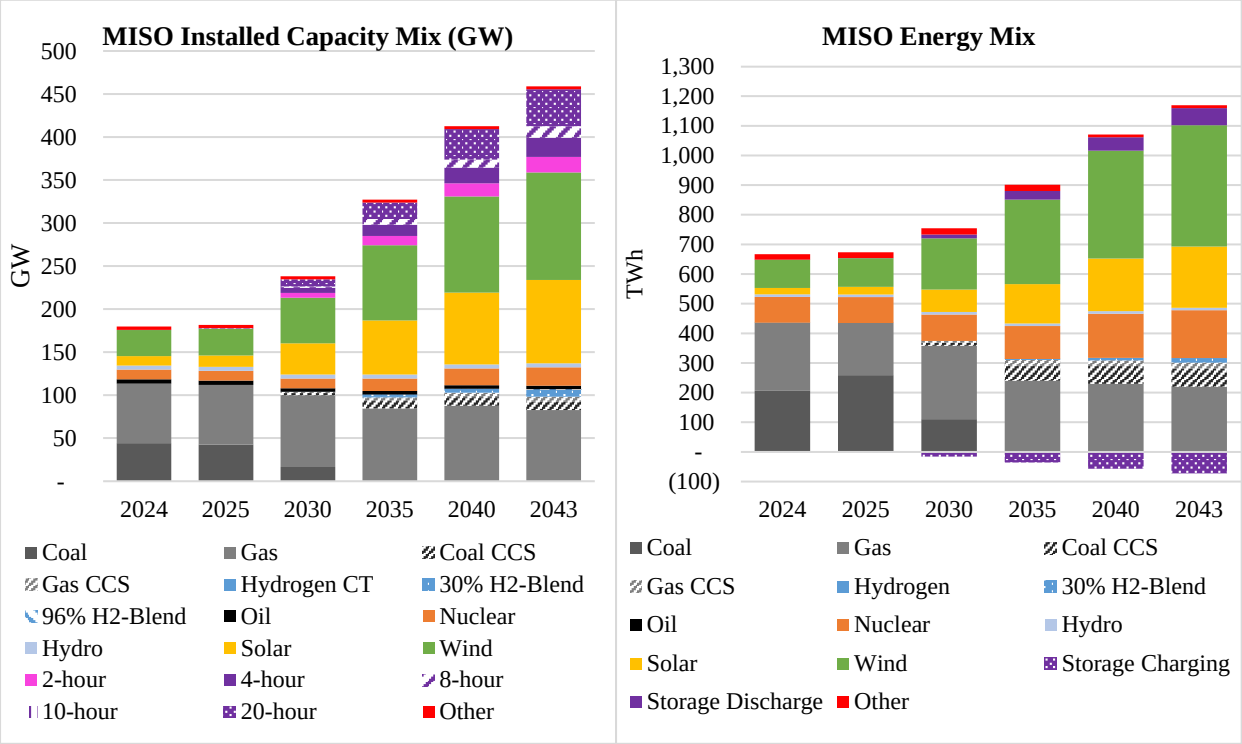
Driver	Reference Case	DR
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Base View
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Base View
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Base View
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Increased power sector & other demand

8.4.3.3 MISO Power Market Dynamics

As noted, increased electric demand is a primary driver of the DR scenario. By 2045, across the MISO footprint, net energy for load across the MISO footprint is projected to be around 300 TWh higher than the Reference Case, with peak demand around 40 GW higher. Given baseline load levels for MISO in 2024 of approximately 700 TWh and 120 GW of net energy for load and peak demand, respectively, the increase in power sector demand for the DR scenario is a significant driver of overall outcomes.

As a result of this significant load growth, additional dispatchable capacity across the MISO footprint is needed to maintain regional reliability and serve growing energy needs. Therefore, although all coal capacity is projected to either retire or retrofit to CCUS by 2032 as a result of the EPA GHG Rule, significant amounts of natural gas capacity is also expected to remain in the system, along with new nuclear, wind, solar, storage, and hydrogen-enabled thermal capacity. Overall, the MISO market is projected to generate over 70% of its energy from clean, non-CO2 emitting resources by 2043, while serving a much larger amount of load when compared to the Reference Case. The remaining generation is expected to come from natural gas. The projected MISO installed capacity mix and generation mix over time for the DR scenario are illustrated in Figure 8-27.

Figure 8-27: MISO Power Market Evolution for DR Scenario



8.4.4 Aggressive Environmental Regulation Scenario

8.4.4.1 Summary Description

The AER Scenario represents a future in which environmental regulations are more stringent than anticipated in the Reference Case. More specifically, beyond the implementation of the EPA GHG Rule, the scenario contemplates a federal carbon tax or cap-and-trade framework that drives towards a net-zero emissions power sector and results in a significant price on carbon. In addition, the scenario includes the assumption that environmental policy restricts natural gas production and drives higher production costs for natural gas, resulting in a higher natural gas price outlook. Overall, the scenario addresses the risk of earlier and higher carbon prices and the risk of higher prices for natural gas and power.

8.4.4.2 Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the AER Scenario's price trajectory. Overall, higher prices are realized primarily through changes in the supply side dynamics for natural gas, including the following assumptions:

- Smaller resource size: Instead of assuming that available gas supply grows over time, the AER scenario assumes that future exploration is limited by policy actions (for example, drilling bans). This is also achieved by anchoring more toward the PGC minimum values for unproven reserves.
- Slower improvements in well productivity: Improvements in technology are assumed to slow over time in the AER scenario, as interest rotates into clean energy sectors due to changing policy incentives.
- Higher fixed and variable well costs: Improvements in technology are assumed to slow, as interest rotates into clean energy sectors due to changing policy incentives. In addition, environmental costs are assumed to increase in the AER scenario to reflect additional regulation of emissions from fossil fuel producing sectors, include natural gas drilling and extraction.

Figure 8-28 summarizes the major natural gas price drivers for the AER scenario relative to those in the Reference Case.

Figure 8-28: Summary of Natural Gas Price Drivers for AER Scenario

Driver	Reference Case	AER
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Limited resource growth, prospective drilling ban
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Base View
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Slower improvement as policy drives investment into clean sectors • Higher environmental costs
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Base View

8.4.4.3 Carbon Regulation

As noted above, the AER scenario assumes a significant price on carbon, which was developed by NIPSCO using public sources to reflect a price on carbon that would be required to limit global warming to 2 degrees Celsius (3.6 degrees Fahrenheit) above pre-industrial levels by 2100.

In the AER scenario, the carbon price starts at $83/metric ton (in real 2023$) in 2030 and increases at a constant rate of 4% annually, as summarized in Figure 8-29.[143] This price would make renewable resources and other clean energy generation more economically attractive, resulting in increased adoption of clean energy resources to meet U.S. electricity demand.

It is important to note that an implicit cost of carbon captures not only an explicit tax on emissions, but a range of possible climate policy outcomes that would increase the overall cost of emitting CO2 into the atmosphere. This approach allows NIPSCO's 2024 IRP to incorporate price outcomes, while also recognizing the significant uncertainty associated with policy design and ultimate implementation.

Figure 8-29: AER Scenario Carbon Price Forecast

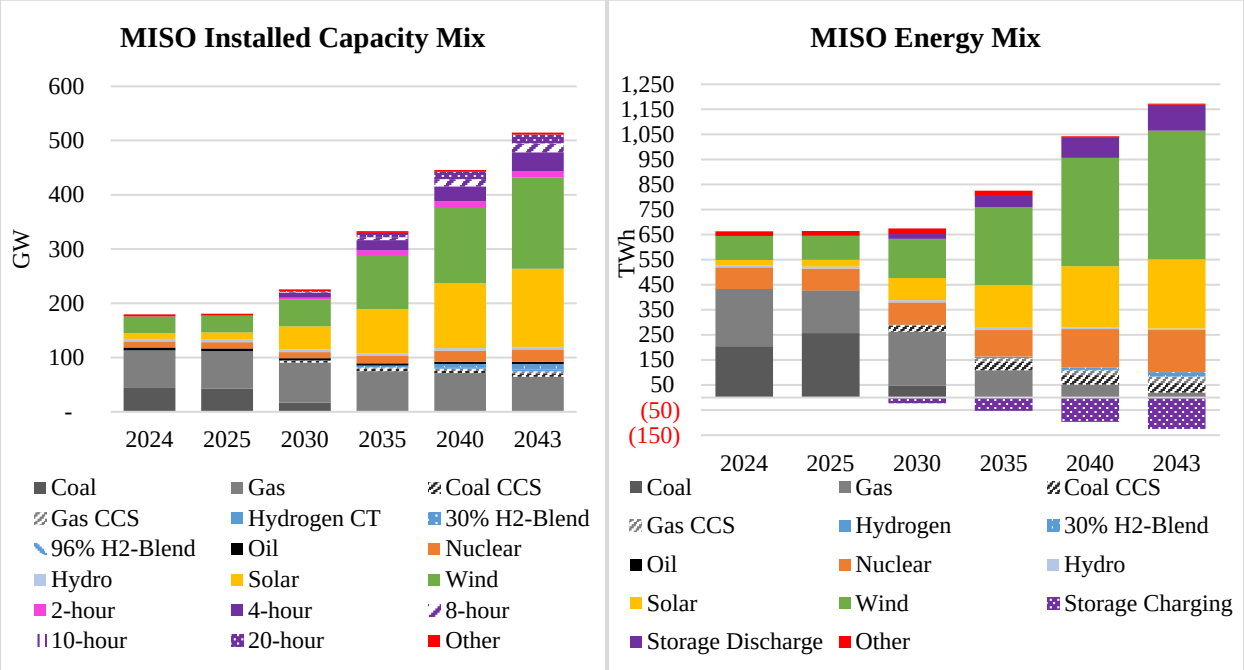


8.4.4.4 MISO Power Market Dynamics

In the AER scenario, higher carbon prices and higher natural gas prices are expected to accelerate both the transition away from fossil-fired resources and towards clean technologies across the MISO market. All coal capacity is projected to either retire or retrofit to CCUS by 2032 under the AER scenario. In addition, new nuclear capacity is projected, and consumption of some hydrogen fuel is expected in both new and existing gas turbine and combined cycle capacity. Overall, the MISO market is projected to generate over 90% of its energy from clean, non-CO2 emitting resources by 2043. This is illustrated in Figure 8-30.

[143] The price trajectory was drawn from work published by the Brookings Institution: Hansel et al, "Climate Policy Curves: Linking Policy Choices to Climate Outcomes," Brookings Institution, December 2022.

Figure 8-30: MISO Power Market Evolution for AER Scenario



8.4.5 Accelerated Innovation Scenario

8.4.5.1 Summary Description

The AI Scenario represents a future in which technological breakthroughs and federal environmental regulations and subsidies drive significant emission reductions throughout the economy *without* imposing a price on carbon. Instead, CO2 emission reductions are assumed to be the result of a substantial technological advancement which reduce the costs of new power sector technologies, including distributed energy resources, electric vehicles, microgrid deployment, and advanced energy efficiency. These innovations are supported by federal rules and incentives, like the EPA GHG Rule and IRA incentives. In addition, electrification measures are projected to significantly increase power demand, with most of this growth concentrated in the winter months due to heating electrification. Overall, the scenario addresses the risk of substantial electrification of the economy (and thus substantial growth in overall load) and transition toward new power sector technologies.

8.4.5.2 Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the AI Scenario's price trajectory. Overall, lower prices are realized primarily through changes in demand for natural gas. Instead of using the AEO Reference Case, the demand for the AI Scenario was based on the Princeton Net Zero Report E-Minus case[144] – a

[144] See https://netzeroamerica.princeton.edu/the-report for the report details.

case which adopts an aggressive net-zero by 2050 goal. Specifically, there is a roughly 20% overall decrease in demand over the forecast period, largely driven by roughly half of the electric demand diminishing.

Figure 8-31 summarizes the major natural gas price drivers for the AI scenario relative to those in the Reference Case.

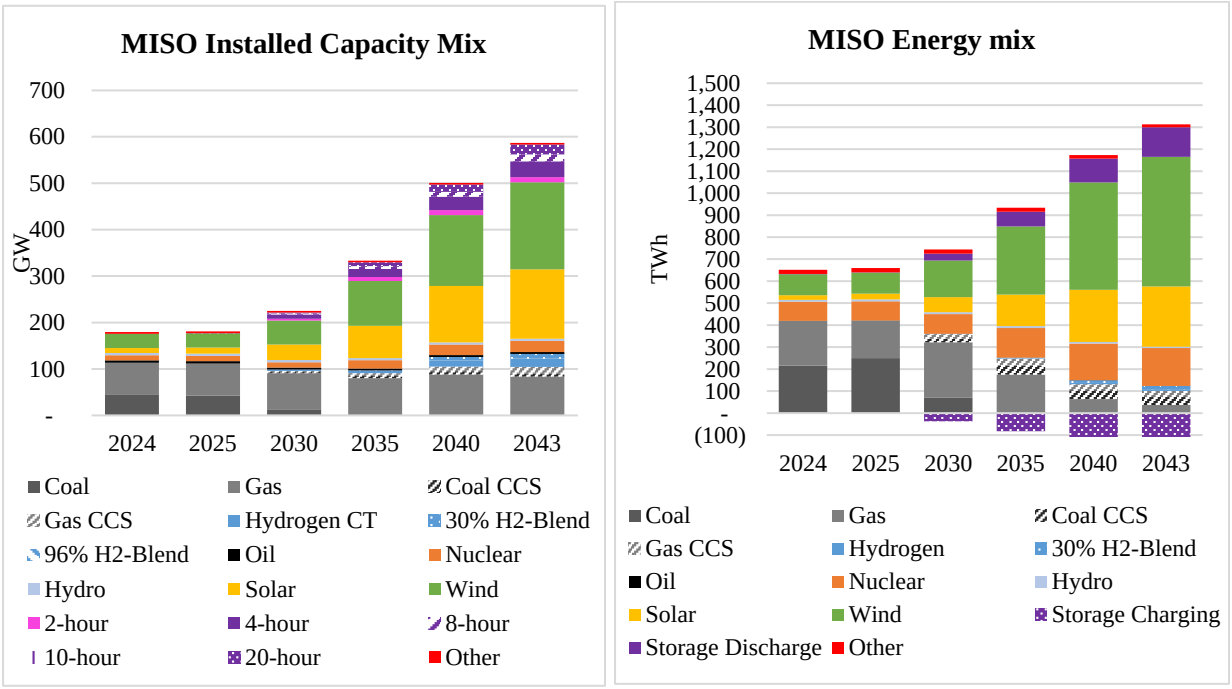
Figure 8-31: Summary of Natural Gas Price Drivers for AI Scenario

Driver	Reference Case	DR
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Base View
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Base View
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Base View
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Significantly decreased electrification demand

8.4.5.3 MISO Power Market Dynamics

In the AI scenario, electrification growth is expected to significantly increase overall demand across the MISO footprint. By 2045, across the MISO footprint, net energy for load across the MISO footprint is projected to be around 200 TWh higher than the Reference Case, with peak demand nearly 40 GW higher. This demand growth is higher than in all other scenarios except for DR. In addition, all coal capacity is projected to either retire or retrofit to CCUS by 2032, while low gas prices are expected to also support natural gas with CCUS generation. Significant demand growth combined with significant capacity retirements is expected to drive the highest overall capacity buildout across scenarios. This includes new nuclear capacity, as well as hydrogen and storage capacity additions which are expected to provide dispatchable capacity to support significant amounts of new wind and solar. Overall, the MISO market is projected to generate over 90% of its energy from clean, non-CO2 emitting resources by 2043. The projected MISO-wide capacity and energy mixes over time for the AI scenario are presented in Figure 8-32.

Figure 8-32: MISO Power Market Evolution for AI Scenario



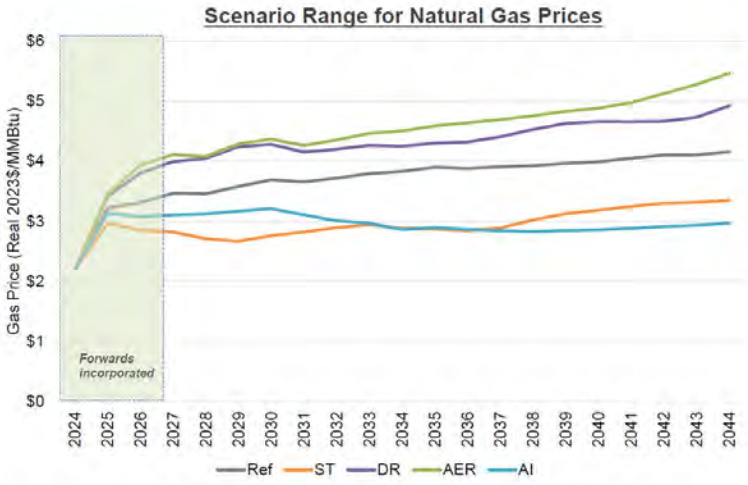
8.4.6 Scenario Comparisons

The following section provides a series of summary comparisons across all five planning scenarios to illustrate the ranges of outcomes NIPSCO has evaluated for key metrics including natural gas prices, carbon regulation, and MISO power market dynamics.

8.4.6.1 Natural Gas Prices

Figure 8-33 summarizes natural gas price projections for the Henry Hub across all five scenarios. The prices range from approximately $2.85 to $4.60/MMBtu (real 2023$) in 2035 and approximately $2.90 to $5.30/MMBtu (real 2023$) by 2043, with the AER scenario ultimately having the highest prices and AI having the lowest.

Figure 8-33: Natural Gas Price Range across Scenarios



	Henry Hub Price (in real 2023$/MMBtu)		
	2025	2035	2043
AER	$3.46	$4.59	$5.28
DR	$3.42	$4.30	$4.73
REF	$3.22	$3.90	$4.11
ST	$2.97	$2.87	$3.32
AI	$3.13	$2.90	$2.93

8.4.6.2 Carbon Regulation

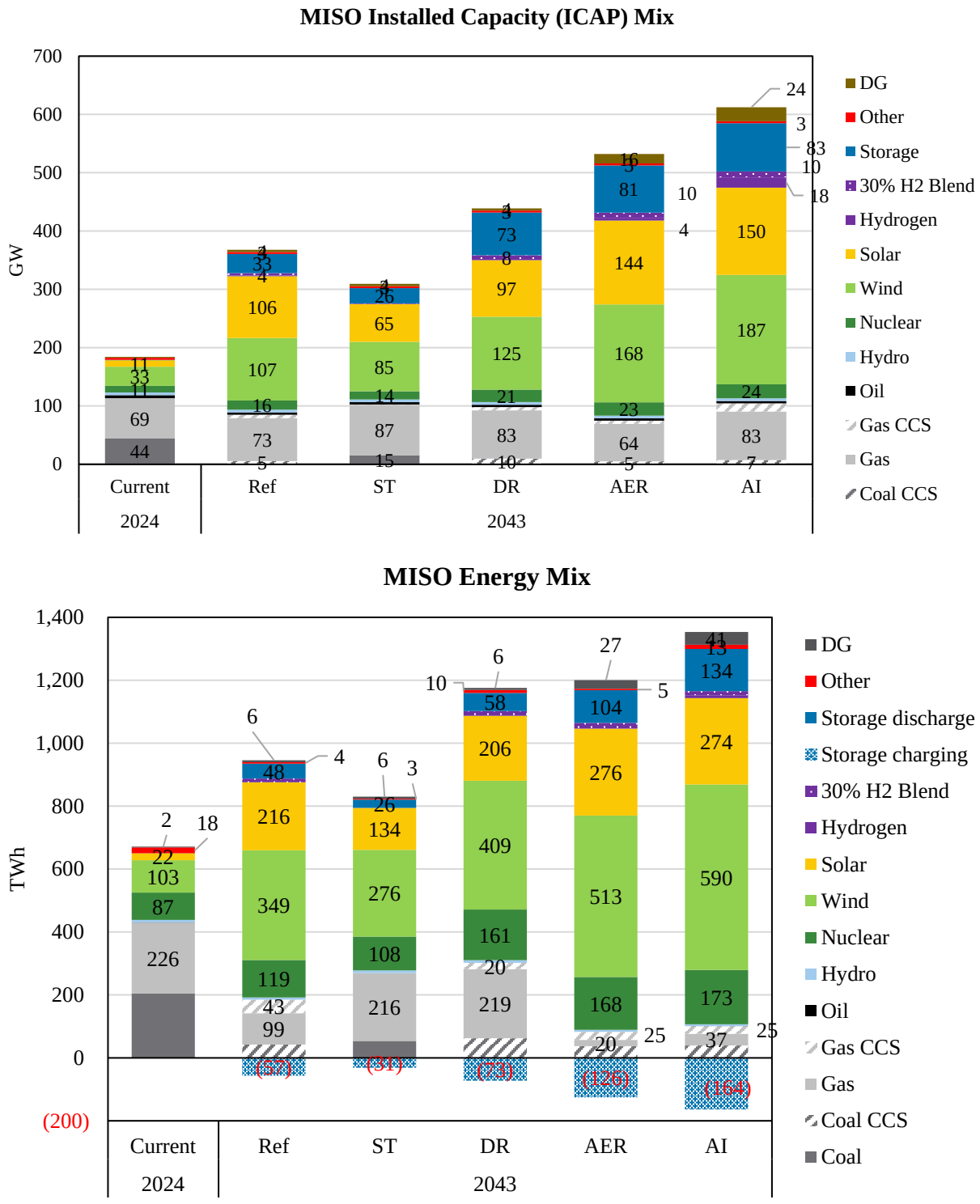
As noted earlier, NIPSCO's scenarios incorporate a range of potential carbon regulation outcomes. Four out of the five scenarios include the EPA GHG Rule, while additional bookend assumptions incorporate the possibility that carbon emissions are not regulated at the federal level over the study horizon as well as the possibility that additional regulation (modeled via a carbon price) pushes towards commitments made by the Biden Administration to limit global temperatures at 2° Celsius above pre-industrial levels by 2100.

8.4.6.3 MISO Power Market Dynamics

The MISO power market is projected to evolve very differently across NIPSCO's five planning scenarios. As discussed earlier, the Reference Case projects a steady transition away from coal capacity and energy towards renewables and, to a lesser extent, natural gas. The ST scenario projects a stronger role for fossil capacity and energy over time, while the DR scenario expects the highest overall load growth, with a significant role for a diverse set of generation technologies, including renewables, natural gas, and nuclear. Finally, the AER and AI scenarios project significant shifts towards renewables and new clean energy technologies, including nuclear, CCUS, and hydrogen. These dynamics are illustrated in Figure 8-34, which summarizes the current MISO capacity and energy mix and the projections in 2043 across all four scenarios.[145]

[145] Note that storage charging MWh are shown below the zero point on the x-axis, while discharging MWh are shown towards the top of the stacked bars.

Figure 8-34: MISO Capacity and Energy Mix Outlook across Scenarios



Given the growing penetration of intermittent energy resources across all scenarios, the hourly generation profiles at the MISO market level are also projected to be significantly different across scenarios over time. This impacts the expected dispatch of various resource types and market prices at the hourly level. Figure 8-35, Figure 8-36, Figures 8-37, and Figure 8-38 all display projected hourly generation projections by resource type at the MISO level for a sample summer, winter, spring, and fall month for 2040, respectively. The figures display expected hourly output for non-dispatchable renewable and nuclear resources, along with gross and net load projections. Major seasonal observations include:

- In the summer, large ramping requirements are likely to develop in the evenings, especially in the AER, DR, and AI scenarios.
- In the winter, higher overnight loads need to be met when solar is unavailable, particularly in the AI case, with high electrification-driven winter loads.
- In the spring shoulder months, mid-day energy output from renewables could be as high as system loads, resulting in low prices and potential curtailment if not stored.

Figure 8-35: MISO Hourly Generation Projections – Summer, 2040

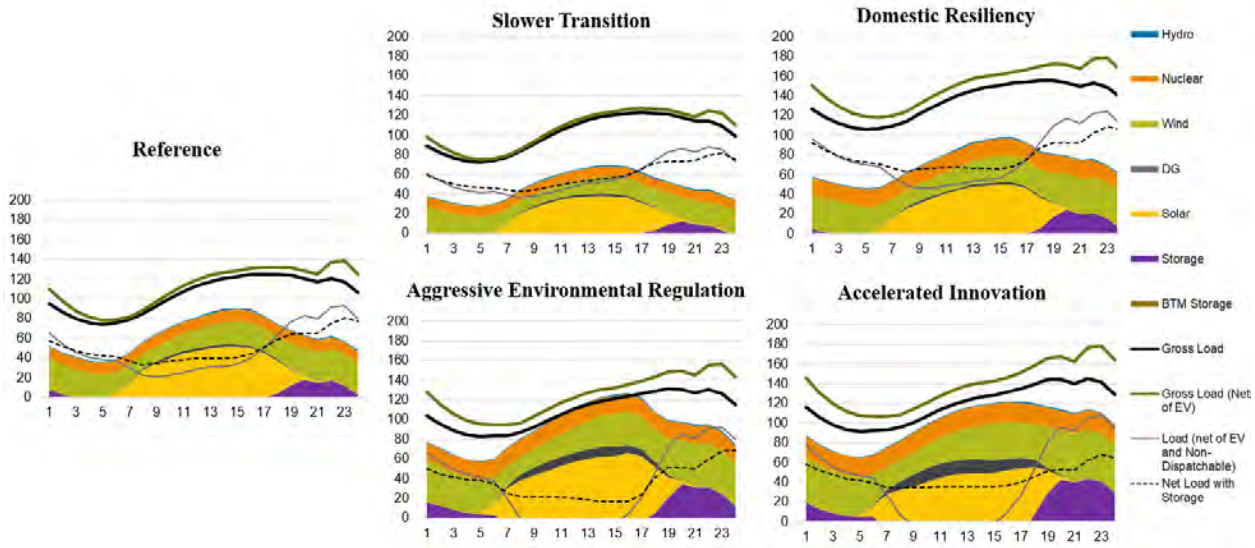


Figure 8-36: MISO Hourly Generation Projections – Winter, 2040

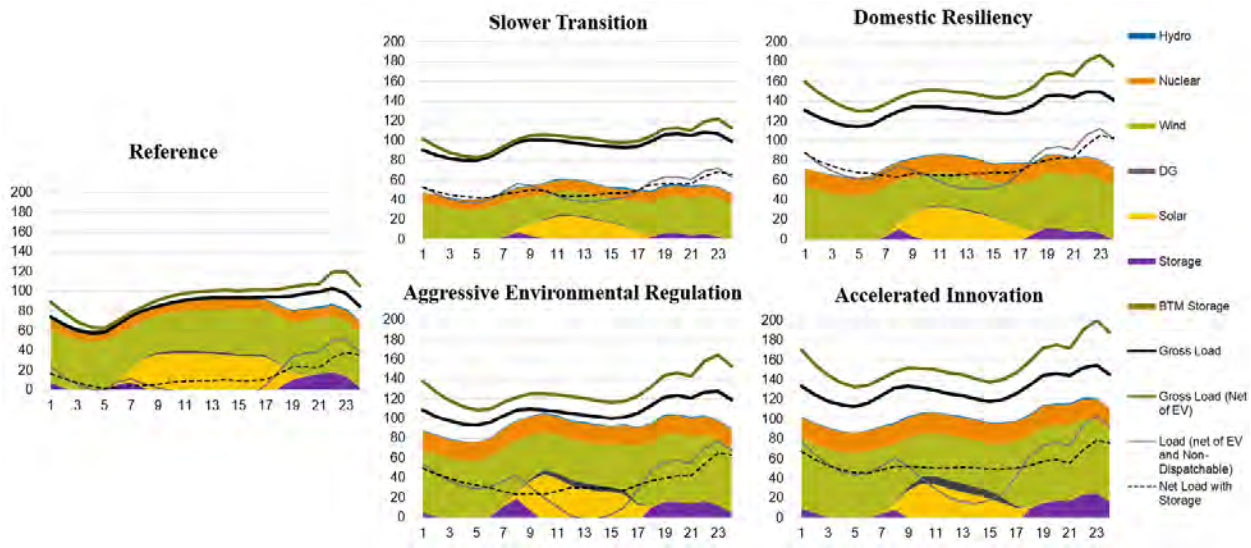


Figure 8-37: MISO Hourly Generation Projections – Spring Shoulder Month, 2040

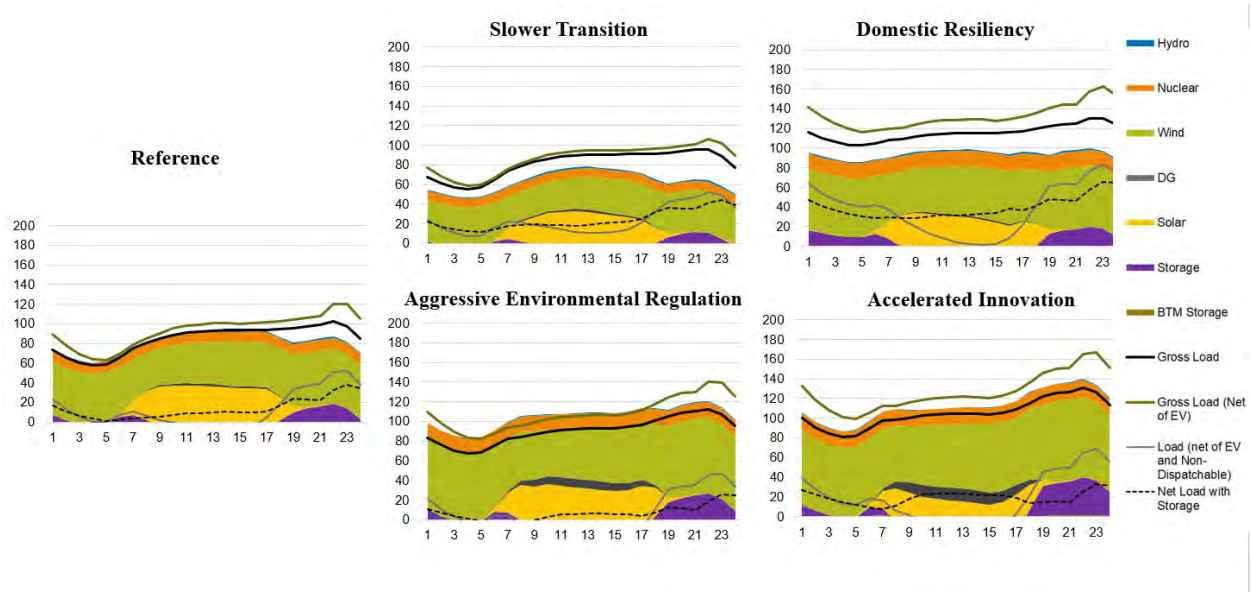
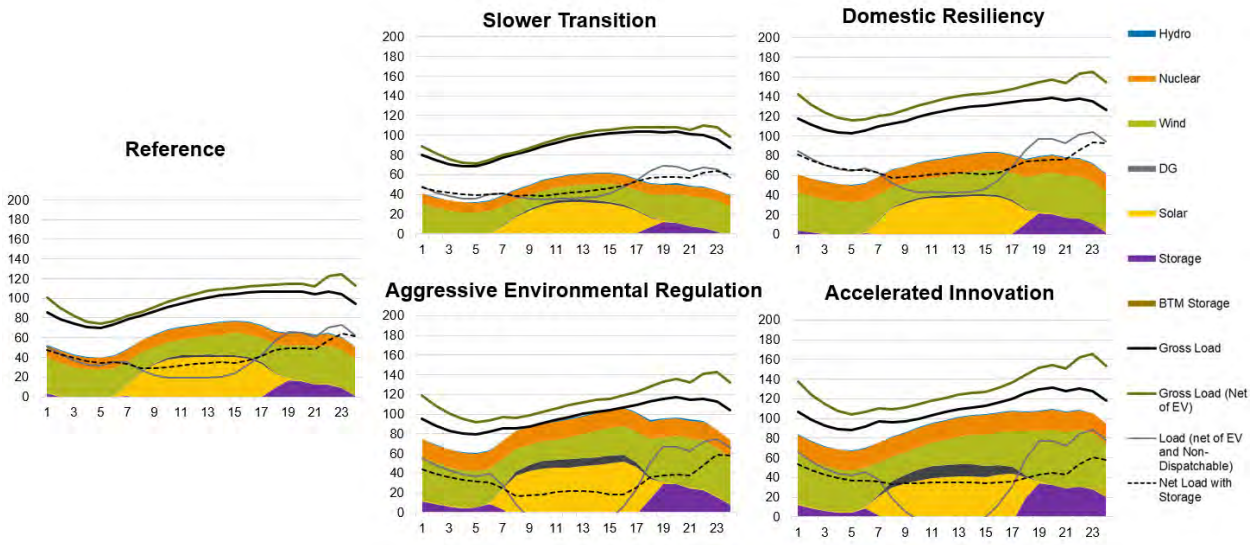


Figure 8-38: MISO Hourly Generation Projections – Fall Shoulder Month, 2040



The different energy market projections contribute to a range of outcomes for MISO-wide clean energy penetration, MISO-wide CO2 emissions, energy prices at various levels of granularity, and capacity prices.

While MISO's generation mix is currently composed of approximately 30% clean energy resources (wind, solar, hydro, other renewables, and nuclear), the four scenarios project this level to grow to between 55% to 75% by 2030 and between 65% to 90% by 2043. Figure 8-39 summarizes the projected clean energy percentages over time across scenarios.[146] Similarly, a range of carbon emission reductions across MISO are projected across the five scenarios. The MISO market has already achieved an approximate 35% reduction in CO2 emissions relative to a 2005 baseline, with an expected reduction of over 50% by 2030 across all scenarios and between 65% and 90% by 2043. This is illustrated in Figure 8-40.[147]

146 Note that the clean energy calculation is based on total MISO clean energy generation (wind, solar, hydro, other renewables, nuclear, CCS, hydrogen), adjusted for projected imports and exports, divided by MISO net load.

147 Historical data from 2005 is taken from MISO Futures documentation.

Figure 8-39: MISO Clean Energy Percentage Projections across Scenarios

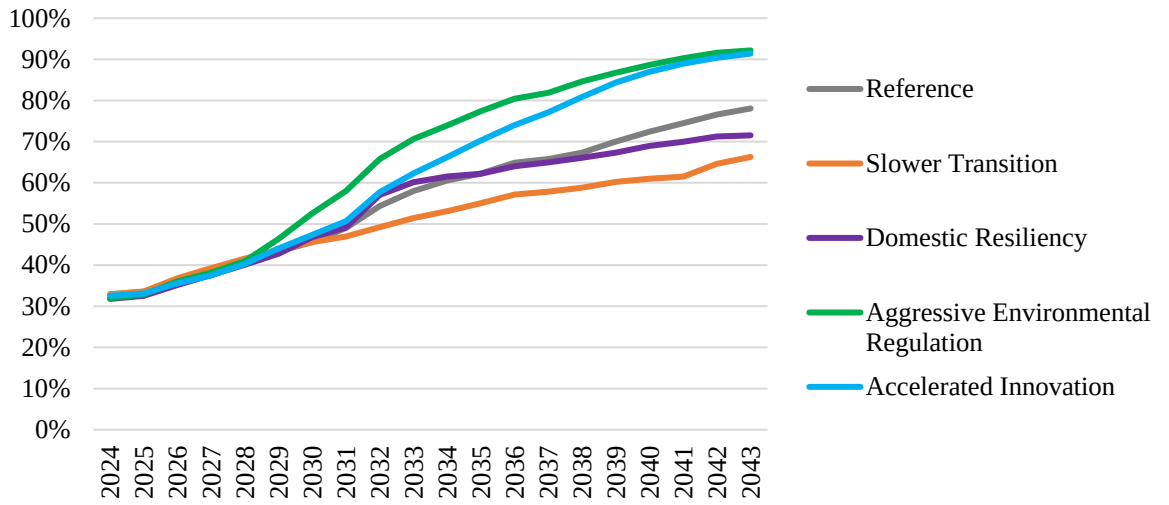
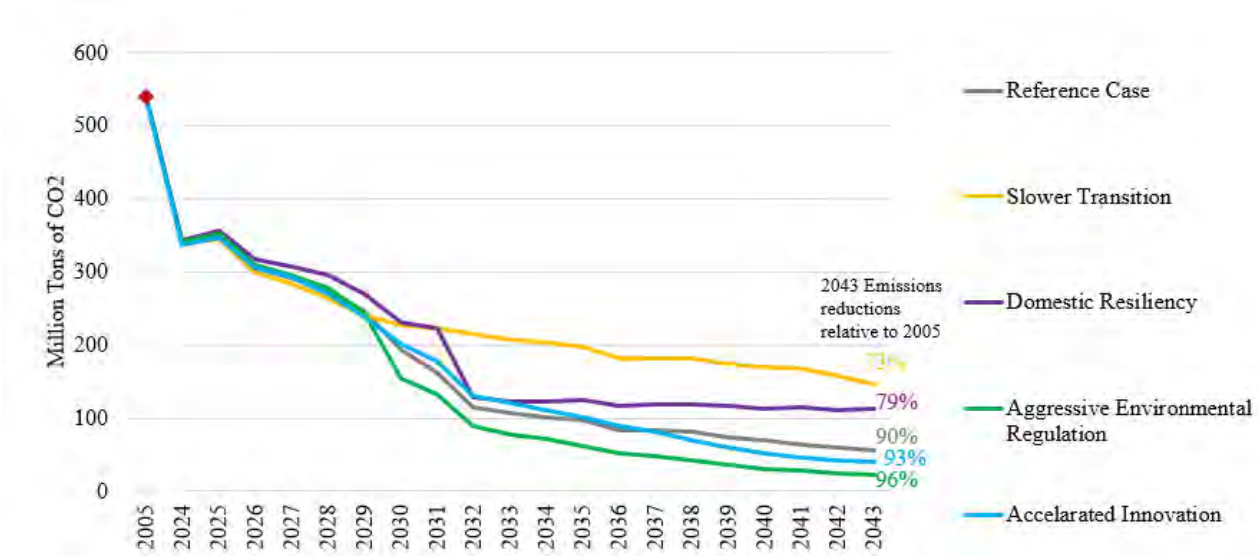
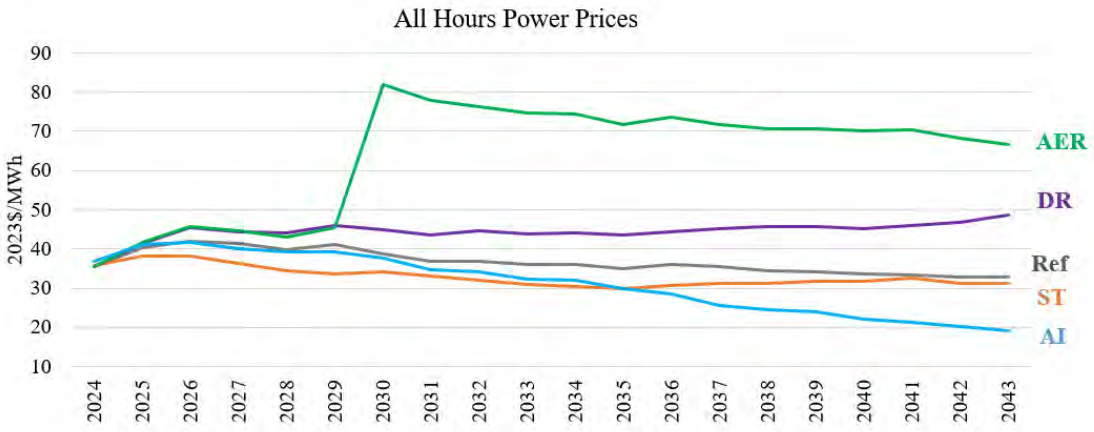


Figure 8-40: MISO CO2 Emission Reduction Projections across Scenarios



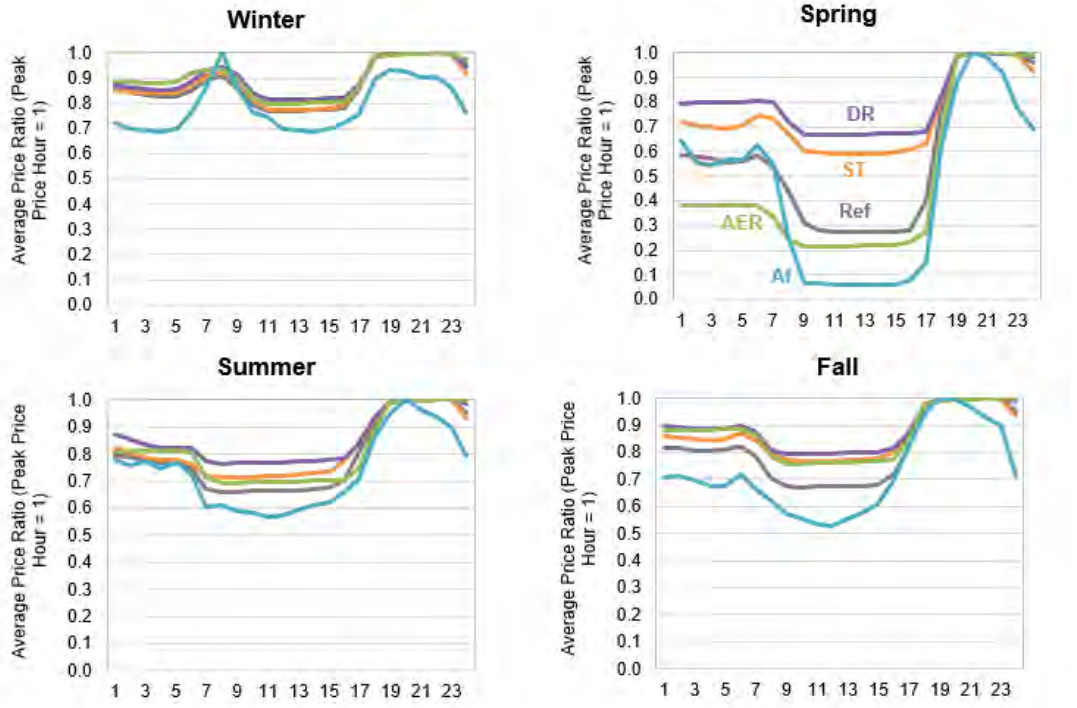
MISO energy prices are projected to vary considerably across scenarios as well. On an "all-hours" or ATC basis, the Reference Case projects prices to be relatively flat in real terms across the study period (as described above) and close to $35/MWh (real 2023$) by 2043, while the scenarios include prices that range between below $20/MWh to above $70/MWh (real 2023$) by the same time. Rising natural gas and carbon prices drive the AER scenario's prices highest, while the ST and AI scenarios have flatter pricing in real terms due to lower gas price expectations, the lack of a carbon price, and expectations for growing zero variable cost renewable energy penetration. Prices in the DR scenario are projected to decline above the Reference Case due to increasing load from industrial onshoring and other large loads, as well as higher natural gas prices. The ATC price projections across scenarios are summarized in Figure 8-41.

Figure 8-41: MISO Zone 6 ATC Power Prices across Scenarios



On an hourly basis, the shape of power prices is also likely to evolve very differently over time, particularly as growing levels of renewable energy enter the market. By 2040, all scenarios are expected to have peak hours shift later into the evening during summer months, while mid-day prices during the shoulder months (spring and fall) are expected to decline significantly as a result of solar energy penetration, particularly in the AER and AI scenarios. This dynamic is shown in Figures 8-42, which illustrates the wide range of hourly market price risk that NIPSCO is evaluating across its scenarios.

Figure 8-42: MISO Zone 6 Hourly Price Shapes by Season (2040) across Scenarios



8.5 Stochastic Modeling and Analysis

As discussed above, NIPSCO identified commodity prices, renewable generation output, and generator availability as stochastic variables for evaluation in its 2024 IRP to help assess resource adequacy metrics and tail risk cost exposure for its potential future portfolio.

8.5.1 Stochastic Analysis Motivation and Key Metrics

NIPSCO operates within the MISO market and is not its own balancing authority, meaning that it does not need to produce a portfolio that meets the desired resource adequacy target ("1-Day-in-10 Years"[148]) on its own. Rather, it benefits from integration into the broader MISO market by pooling reliability risks and responsibilities toward meeting resource adequacy targets. However, NIPSCO is committed to ensuring reliable service to its customers and recognizes that it must bring its fair share of resource adequacy to the broader MISO system. Thus, as part of its stochastic analysis for the 2024 IRP, NIPSCO has performed an assessment of the frequency and magnitude of events when it might be forced to rely on the market.

During normal operations, NIPSCO will operate the system economically and buy and sell energy on the market when it is cost-optimal to do so. However, NIPSCO may experience periods of forced market exposure when its native load is greater than its owned and contracted generating capacity, due to planned or unplanned generating outages, low renewable generation, and/or unusually high load demand. During these "pseudo-loss of load" events, NIPSO *must* rely on the market. This leaves NIPSCO potentially exposed to high market prices during these forced market exposure events and in extreme cases, exposed to loss of load events if these periods of NIPSCO stress align with periods of MISO-wide stress events.

To evaluate these risks, NIPSCO elected to employ a loss of load style study – treating NIPSCO's system as an island – to identify pseudo-loss of load events when NIPSCO is forced to rely on the MISO-market to meet its customers' electricity demand. This entails evaluation of portfolios against metrics like loss of load expectation and unserved energy, which are proxies for the frequency and magnitude of "forced market exposure" events. NIPSCO has also qualitatively compared the periods of NIPSCO system stress with the periods of stress identified by MISO in its recent loss of load studies.[149]

In addition, NIPSCO explored the impact of a sample of stochastic inputs to assess the customer cost impact of various portfolio options. Using the Monte Carlo samples generated in the stochastic analysis study, NIPSCO selected 100 representative samples to assess the 95th and 5th percentiles of customer costs for a sample year.

148 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

149 https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

8.5.2 Stochastic Modeling Approach

The stochastic analysis approach broadly encompassed the following four steps:

1. **Input data development**, including development of fundamental forecasts (as described above), and review of historical price, weather, and generator availability data (both forced and planned outages);

2. **Statistical and fundamental analysis**, including developing statistical models to generate multiple weather outcomes, including around physical climate risk; converting these weather outcomes to wind/solar generation, *future looking* load demand, and generator availability; and learning the impact of net load on the power price;

3. **Stochastic modeling**, including generating a large number of simulated commodity prices and renewable generation, load demand, and generator availability for a single study year (2030); and

4. **Portfolio analysis and results** using the stochastic models to evaluate and report key metrics for NIPSCO's integrated scorecard.

The remainder of this section provides an overview of the first three steps in the overall process, outlining the data development, analysis, and statistical model development and simulation. The portfolio analysis and results are reported in next Section.

8.5.3 Input Data Development

8.5.3.1 Fundamental Forecasts

The commodity price stochastic inputs were developed around the Reference Case natural gas and power price forecasts outlined earlier in this Section. NIPSCO's stochastic analysis for the 2024 IRP is centered on the Reference Case fundamental forecasts for natural gas and MISO power prices as described above in Section 8.2.

Historical Commodity Price Data

Historical daily average gas and power price data were gathered to observe key price characteristics and calibrate simulation model parameters to reflect realistic market price behavior. These characteristics include, but are not limited to, standard deviation, range of prices around a seasonal median price, magnitude and frequency of sudden price spikes, market heat rate, and correlation between natural gas and power prices. Historical prices from the period January 1, 2014 through December 31, 2023 were used to summarize relevant market price behavior and constrain the dataset to include only the most recent market dynamics. This limits the dataset but has the benefit of excluding data from periods of time with different natural gas fundamentals and with a MISO market generation mix that was very different than today's. The daily gas spot index

from Chicago Citygate and the day-ahead ATC price strip from the NIPSCO zone within MISO (Zone 6) were the specific pricing points used in this analysis.[150]

8.5.3.2 Historical Weather and Solar / Wind Availability Data

Historical weather data was gathered at locations of present and potential future utility scale wind and solar farms. Solar data was obtained from the NREL NSRDB[151] for weather years 2002 to 2022. The data included key meteorological descriptors including diffuse horizontal irradiance, direct normal irradiance, albedo, wind speed (meters per second) at surface level, temperature, snow depth, elevation above sea level, atmospheric pressure, and wind direction, among others. The weather data was converted to solar generation using Sandia National Laboratories' open source python-based tool pvlib-python[152]. This python-based tool takes data in the NSDRB format and provides relevant solar generation. Wind data was obtained from the NREL Wind Integration Datasets[153] for weather years 2007 to 2014. This data included wind speed and wind temperature at various elevations (i.e., 80-meter height). The weather data was converted to wind generation using publicly available power curves,[154] based on the actual or assumed turbine type.

The annual solar and wind generation were then checked to ensure the correct average annual and monthly capacity factors were achieved based on NIPSCO-specific project historical performance or future expectations. The weather data was also utilized to synthesize a representative temperature time series, wind speed at hub height time series, and wind speed at surface level using a weighted average of the various renewable sites, based on the respective installed capacities. This is a reasonable approximation to represent the weather variables as a single weighted average time series, since these values are highly correlated (correlation coefficients between .8 and .95).

The process outlined above resulted in eight historical hourly trajectories for wind generation at each wind farm location (representing historical weather years 2007 through 2014) and twenty-one historical hourly trajectories for solar availability (representing historical weather years 2002 through 2022). The NREL simulations produced reasonable annual average capacity factors for wind and for solar in the selected location (around 35-40% for a representative wind resource and around 25% for a representative solar resource).

150 Data was retrieved from S&P Global Market Intelligence: Commodity Charting Tool.

151 NREL NSRDB, https://nsrdb.nrel.gov/

152 https://github.com/pvlib/pvlib-python

153 NREL Wind Integration Datasets, https://www.nrel.gov/grid/wind-integration-data.html

154 Wind energy database (thewindpower.net)

8.5.4 Statistical and Fundamental Analysis

Next, statistical models were developed to generate random iterations of commodity prices, generator availability, load demand, and wind/solar generation and to capture the correlations between them.

8.5.4.1 Integrating Renewable Output Uncertainty

The integration of renewable output uncertainty into NIPSCO's stochastic analysis process was an enhancement originally deployed for the 2021 IRP. Given the significant growth in intermittent renewable capacity within NIPSCO's portfolio (and the broader MISO market), incorporating the risk of renewable output uncertainty allowed NIPSCO to assess a broader range of risks associated with energy market exposure as market dynamics evolve. This 2024 IRP continues to further develop this integration of uncertainty into the IRP process to better assess the risk associated with anomalous weather conditions and unusual market prices by generating multiple synthetic weather years (and corresponding renewable generation) to stress test a wide range of weather conditions.

To generate these synthetic wind/solar shapes, statistical models were developed to simulate possible iterations using *CRA AdequacyX* – Charles River Associates' proprietary probabilistic reliability analysis tool. Importantly, CRA used recent weather data to train the probabilistic model to ensure recent weather trends, including those associated with recent local climate change impacts, are incorporated rather than relying on a 30 to 40 year history. Consistent weather data was used across processes associated with the development of wind and solar output, NIPSCO load, and thermal unit availabilities.

These weather shapes include potential annual temperature shapes and possible wind shapes at hub height. These wind speeds at hub height were mapped to the wind speed at the surface, using a machine learning model. These simulated weather conditions mapped to the respective wind and solar generation using the calibrated wind power curve and the calibrated solar power curve (pvlib) described above. Sample illustrations of the temperature, wind, and solar output profiles are shown in Figure 8-43, Figure 8-44, and Figure 8-45. The figures display the range (shown in light blue) and average outcomes generated from 100 Monte Carlo simulations. As highlighted in these figures, the exact renewable generation can vary within a given Monte Carlo iteration, but these iterations capture characteristic daily and seasonal variations.

Figure 8-43: Sample Monte Carlo Iterations for Ambient Temperature

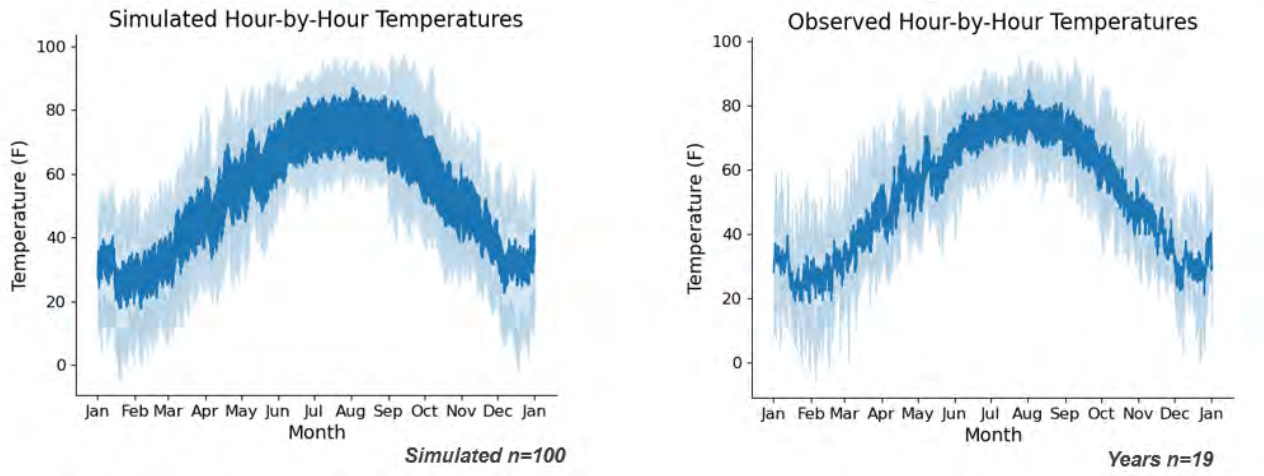


Figure 8-44: Sample Monte Carlo Iterations for Solar Generation

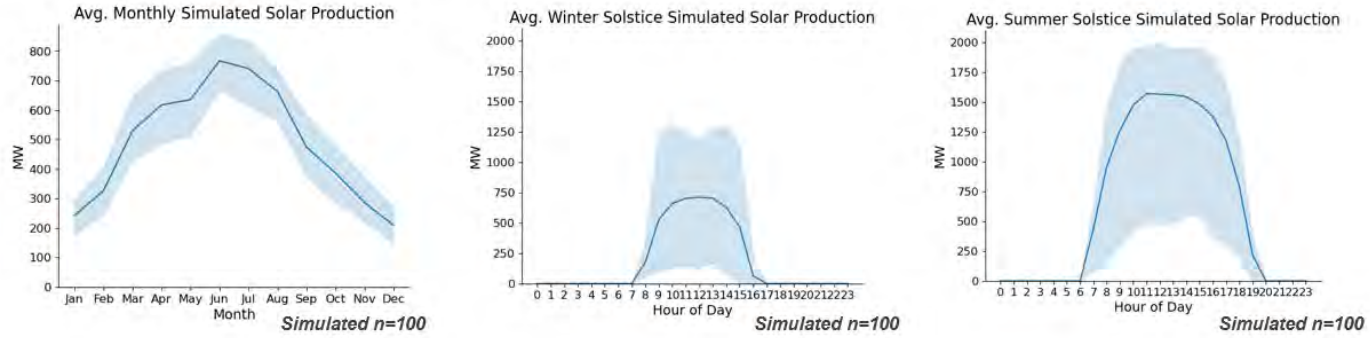
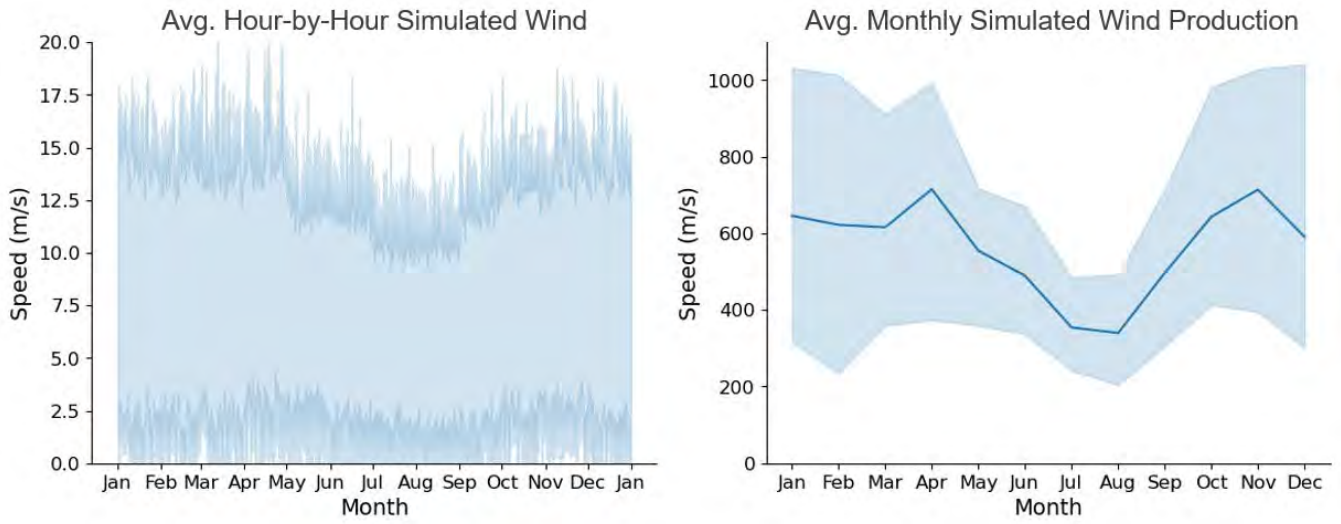


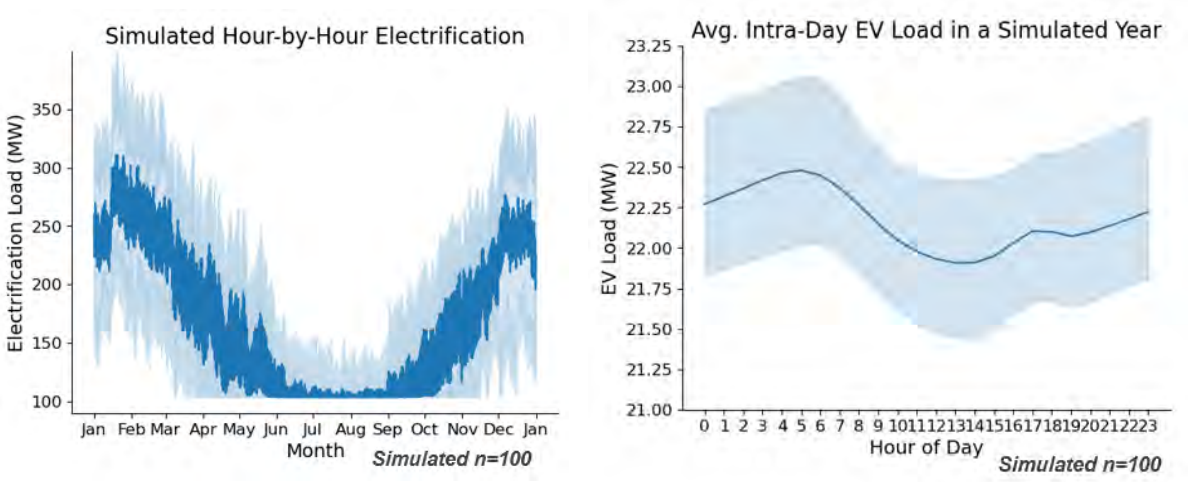
Figure 8-45: Sample Monte Carlo Iterations for Wind Speed and Generation



8.5.4.2 Integrating Load Uncertainty

In addition to driving the wind and solar generation, weather conditions greatly impact demand for electricity in NIPSCO's system. To capture these temperature impacts on demand, NIPSCO developed a regression model between HDD and CDD and load. Using this regression model, NIPSCO generated synthetic load shapes by "temperature shocking" a randomly selected historical hourly load shape (from years 2013 to 2022) by removing the temperature impact of historical temperature and adding back the predicted temperature impact of the synthetic temperature shape. NIPSCO also simulated changes occurring within the load shapes due to the addition of new technologies like electric vehicles, grid electrification, and data centers. NIPSCO developed additional regression models to model the impact of ambient temperature on the electric vehicle charging behavior and electrification (See Figure 8-46). In this manner, NIPSCO generated high-fidelity synthetic load shapes which simulate stress periods over a wide range of times and capture changing load shapes.

Figure 8-46: Sample Monte Carlo Iterations of Additional EV Charging and Demand from Electrification



8.5.4.3 Integrating Thermal Generator Availability Uncertainty

The availability of thermal resources also impacts the resource adequacy and cost exposure of NIPSCO's potential portfolios. A resource may not be available to meet the net load demand due to a planned or unplanned outage, and simulating generator availability was an enhancement for the 2024 IRP relative to previous IRPs. The planned outages were simulated using the historical outage schedules, while forced outages were simulated assuming an exponential distribution, based on the historical seasonal mean time between failure and the mean time to repair. In some regions (including MISO as a whole[155]), weather conditions have been shown to have an impact on the failure rates of generators. Some generators have been shown to be more likely to fail due to very high or very low temperature. Unlike other resources in the MISO

155 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

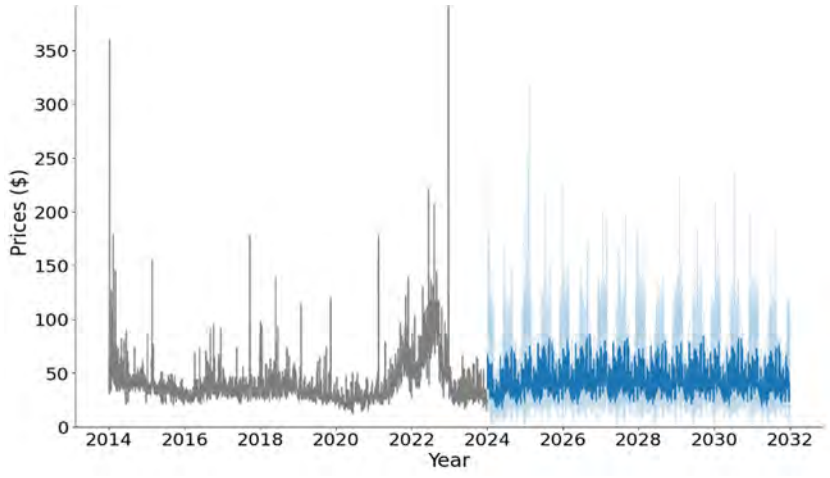
footprint, historical outages at NIPSCO's Sugar Creek natural gas combined cycle unit were not found to be correlated with temperature but were found to have seasonal variations. As such, these generator outages were simulated independently of the weather, while any additional thermal resources were modeled as matching the published MISO forced outage rates.[156]

The ambient temperature can also impact the maximum generating capacity of various technologies, and the temperature impact on the contribution of wind generation, solar generation, and natural gas-based technologies was also modeled.

8.5.4.4 Commodity Price Uncertainty using MOSEP

To develop stochastic price paths for natural gas and power prices, CRA simulated daily natural gas and power price volatility using its MOSEP model. MOSEP is a regime-switching, mean-reverting model[157] that takes as input expected paths for electricity and natural gas prices developed through the fundamental forecasting analysis described earlier in this Section. The tool's Monte Carlo engine simulates price deviations around the expected paths based on historical volatility and natural gas-power correlation to yield "actual" or "realized" price paths. The model parameters are calibrated to historical gas market and MISO power market price behavior. The distribution of possible future electricity prices that NIPSCO developed for its stochastic analysis is shown in Figure 8-47, and the distribution of possible future natural gas price iterations is shown in Figure 8-48. As illustrated, the stochastic price paths exhibit a wide range of possible outcomes and can experience short spikes in price. This is consistent with historical behavior.

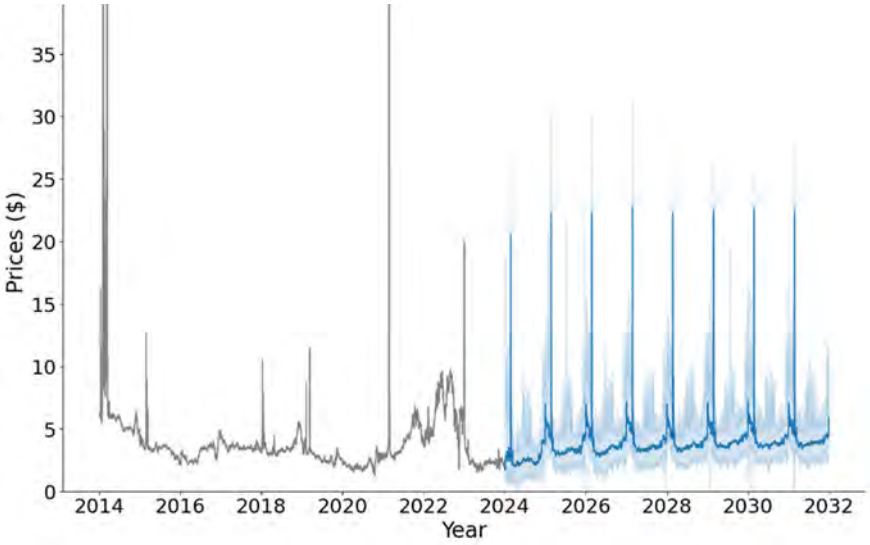
Figure 8-47: Future Electricity Price Iterations (Hourly)



156 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

157 Commodity prices have been found to exhibit a mean-reverting behavior. The regime-switching feature of the model allows for simulation of price spikes by modeling different price regimes (e.g., normal price regime, spike price regime). The simulated switching between regimes is facilitated by a transition matrix. Given the current regime, the transition matrix specifies the probabilities of staying in the current regime or moving to a different regime. The probabilities are estimated based on historical data. For references, see the following paper, on which MOSEP is based - Higgs, H. & Worthington, A. "Stochastic price modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market." Energy Economics, 2008.

Figure 8-48: Future Natural Gas Price Iterations (Daily)



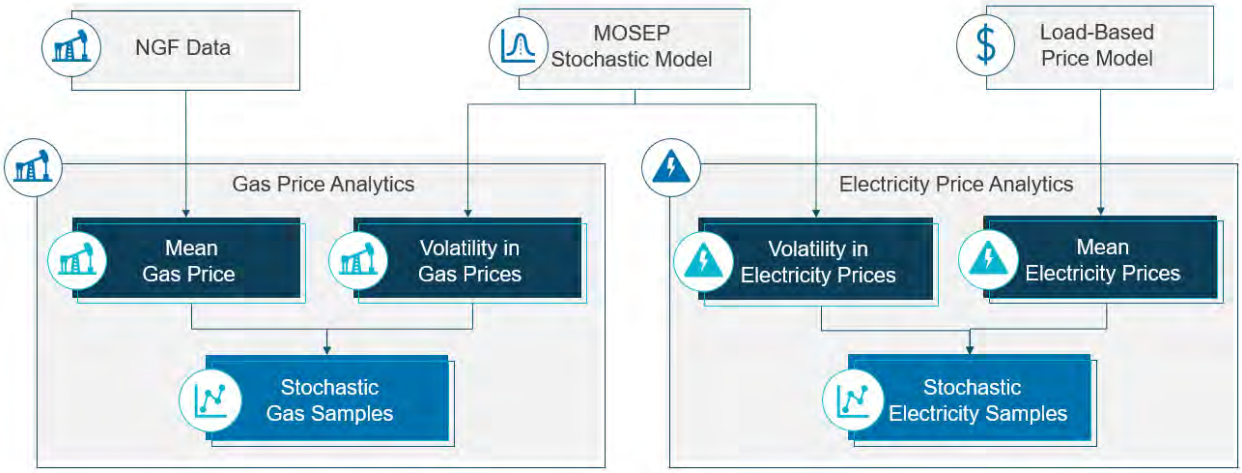
MOSEP generates its potential power prices in a manner that assumes power prices and NIPSCO's net load (load less renewable output) and the highly correlated Zone 6 net load evolve independently of each other. This assumption does not account for the fact that lower than expected net load will generally depress prices by reducing the generating capacity needs to meet the net load. Thus, an additional step was added to the analysis to capture this correlation by modifying the expected electricity price (the assumed mean in the MOSEP model), based on the NIPSCO/Zone 6 net load conditions. To this end, a machine learning model was trained to predict the Zone 6 prices as a function of the NIPSCO/Zone 6 net load, NIPSCO/Zone 6 gross load, and month of year.[158] This model was a regression model trained using the Aurora market simulations. The inputs to this model were the net load, natural gas prices, and timestamp variables from the Aurora market model, and the model's output was the Zone 6 market price.

Additionally, the expected electricity price was adjusted to account for realized conditions before feeding it into the MOSEP model.[159] This process is summarized in Figure 8-49. It is important to note that other factors – like MISO-wide net load, generator outages (both for NIPSCO and non-NIPSCO entities), congestion, and power trading – can all have a substantial impact on NIPSCO's market price (LRZ6). The impacts of these factors are captured through the deviations from the mean and random shocks simulated through the MOSEP model.

[158] This machine learning model represents a "surrogate model" proxy for the computationally time-consuming Aurora model. See Koziel, S., Ciaurri, D. E., & Leifsson, L. (2011). Surrogate-based methods. Computational optimization, methods and algorithms, 33-59.

[159] The predicted electricity price is shifted by the delta between the model's prediction using the percentage realized net load and the expected net load. In this manner, lower than expected net load conditions will shift electricity prices up, and lower than expected net load conditions will shift electricity prices down.

Figure 8-49: Illustration of Renewable Availability Integration in Stochastic Process



Section 9. Portfolio Analysis

9.1 Portfolio Development

9.1.1 Process Overview

As discussed in more detail in Section 2, NIPSCO performed its portfolio analysis in the context of emerging market trends associated with MISO capacity accreditation rules and GHG Rule (*See* also Section 7). As such, different portfolio concepts were evaluated across a range of capacity accreditation expectations and carbon emissions intensity limits. To develop different portfolio concepts, NIPSCO deployed least cost portfolio optimization analysis and then subjected the portfolios to a range of risks and uncertainties, as described in Section 8. To evaluate portfolios, NIPSCO used an integrated scorecard approach, as outlined in more detail in Section 2. In addition to the net present value of revenue requirements in the Reference Case, NIPSCO has also considered rate stability, carbon emissions, reliability, and local economic impact metrics. The overall process included the following major steps:

- Identify six thematic portfolio concepts based on MISO capacity accreditation rules and portfolio carbon emission intensity.
- Identify the least-cost capacity additions to fill incremental capacity needs based on the constraints within each of the six portfolio themes and based on the results from the RFP conducted by NIPSCO and other available supply-side and demand side resources (*See* Sections 4 and 5 for more detail on these resource options).
- Evaluate each portfolio in the IRP tools for each scenario and across the stochastic risk distributions (as defined in Section 8). The evaluation includes a full accounting of the variable and fixed costs of providing generation service.
- Record costs, risks, and other metrics in the integrated scorecard to identify the preferred portfolio.

Importantly, and consistent with prior NIPSCO IRPs, the process of portfolio development focuses on overall cost of each portfolio (in terms of NPVRR) and does not address cost allocation or cost recovery.

9.1.2 Portfolio Concepts

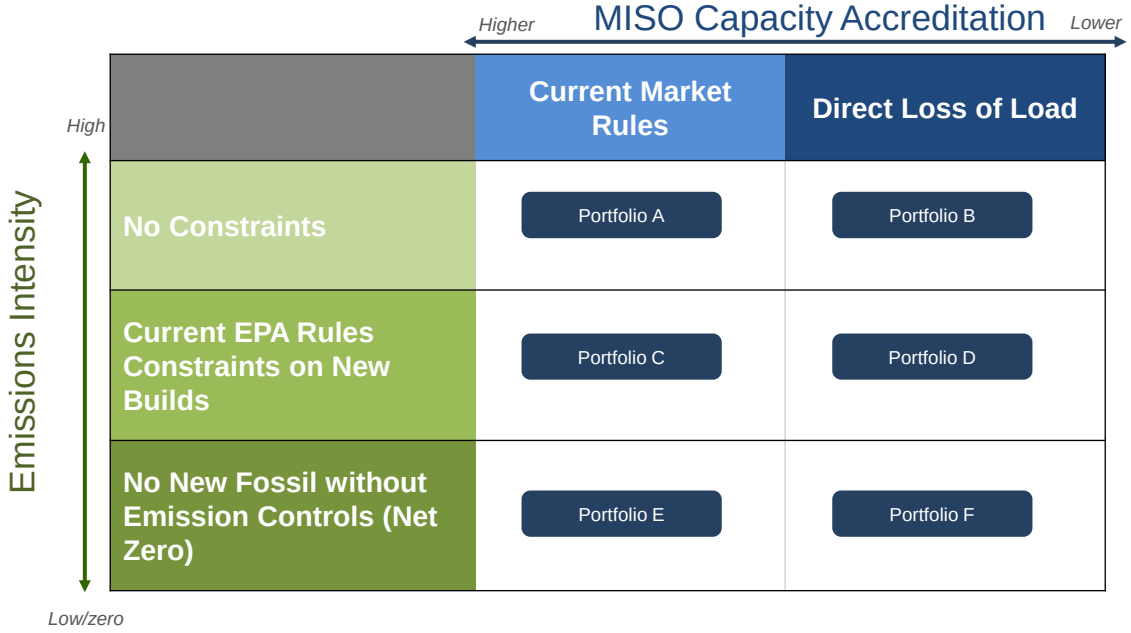
NIPSCO initially developed six portfolio concepts to highlight the two primary market trends and operational uncertainties currently facing the portfolio, as summarized in Figure 9-1:

- MISO's D-LOL rules[160], which are likely to reduce the capacity value, primarily for solar and wind resources; and

- EPA's GHG emissions rules[161], which constrain output or increase cost of new gas generation.

This framework allowed for the definition of six portfolio concepts within a two by three matrix (Portfolios A through F as shown in Figure 9-1). Portfolios were developed under expectations for market capacity accreditation under the current MISO rules and those associated with MISO's D-LOL construct and across three different carbon emission intensity levels: (i) no constraints, (ii) enforcement of capacity factor constraints on new natural gas additions, and (iii) the disallowance of any new fossil-fired resources without carbon emission controls.

Figure 9-1: Overview of Existing Fleet Portfolios



9.1.3 Portfolio Optimization Analysis

As in the 2018 and 2021 IRPs, NIPSCO's All-Source RFP provided insight into the supply and pricing of resource alternatives available to NIPSCO (*See* Section 4 for details on the process and the costs and operational parameters of the individual tranches used for evaluation). In

[160] As discussed further in Section 2, MISO's D-LOL filing was approved by the Federal Energy Regulatory Commission on October 25, 2024 and is expected to be implemented in the 2028/29 planning year. NIPSCO's portfolio development process was initiated prior to this approval and included analysis based on both the D-LOL construct and the prevailing market construct prior to D-LOL implementation. Given continued lack of clarity regarding *actual* future resource accreditations under the D-LOL reforms, the "Current Market Rules" construct remains instructive with regard to the portfolio implications associated with higher resource accreditation values for certain technology types.

[161] As discussed further in Section 7, the EPA's GHG rules were issued on April 25, 2024. Most importantly for NIPSCO's portfolio construction, they would place operational limits on new natural gas-fired resource additions.

addition, NIPSCO identified other resource options (*See* Section 4) and bundles of DSM resource options over time (*See* Section 5) to include in the analysis.

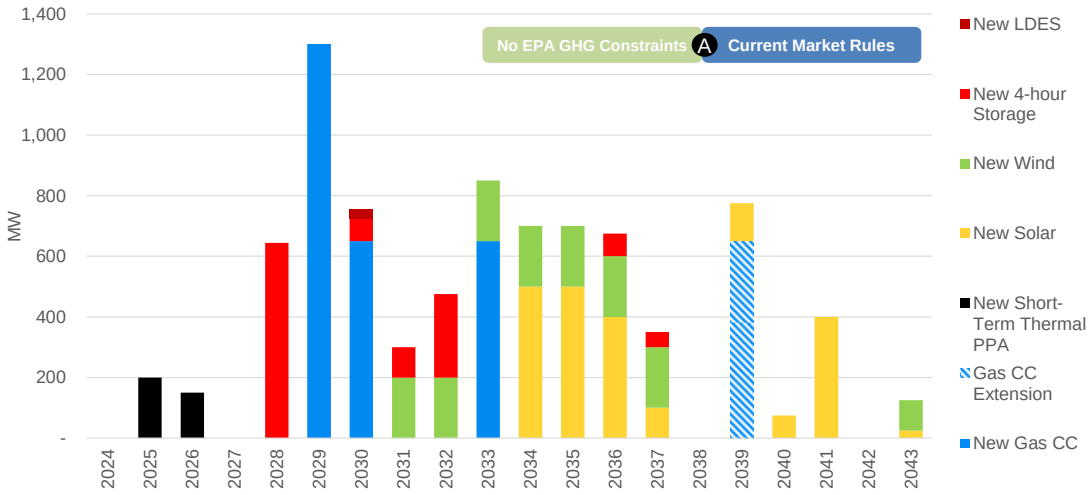
With these resource options, a least cost capacity expansion analysis was performed within Aurora's portfolio optimization tool under each of the six portfolio concepts to identify least-cost sets of new resources under Reference Case market conditions. The portfolio optimization modeling was performed to find the least cost portfolio that would simultaneously meet all MISO seasonal reserve margin requirements along with any other resource constraints.[162]

The remainder of this section documents the resource additions identified in the portfolio optimization process for each of the six portfolio themes.

9.1.3.1 Portfolio A – No EPA GHG Constraints and Current Market Rules

Portfolio A included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,600 MW of combined cycle capacity (1,300 MW through 2029), 1,249 MW of new storage capacity (644 MW through 2029), 1,500 MW of wind, and 2,125 MW of solar over the twenty-year study period. Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio A.

Figure 9-2: Portfolio A – Annual Resource Additions (Nameplate MW)



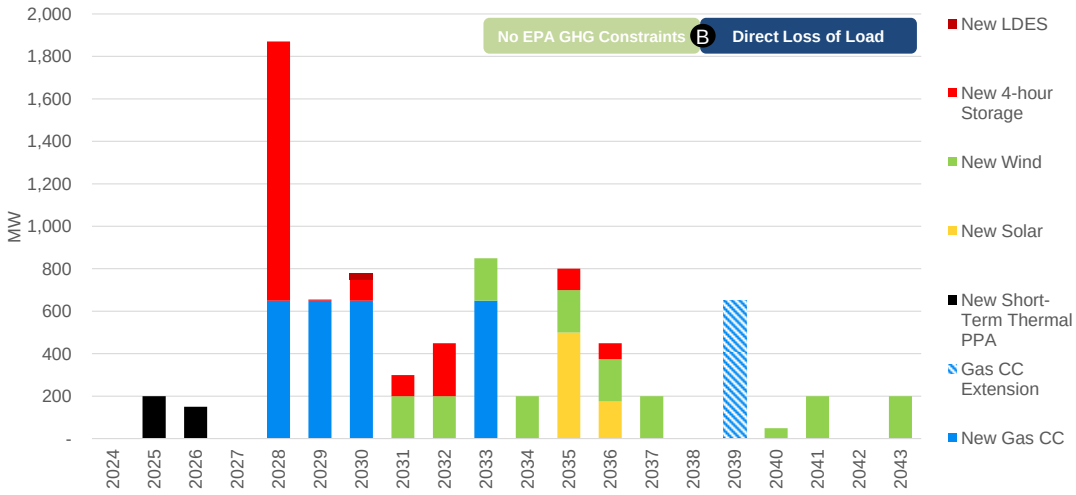
Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

[162] A maximum net energy sales limit of 10% after 2028 (after the retirement of NIPSCO's last coal-fired plant) was targeted, along with a maximum net energy purchases sales limit of 20%. The limits were ultimately input on a monthly level to coincide with the monthly capacity and reserve margin optimization that was performed.

9.1.3.2 Portfolio B – No EPA GHG Constraints and D-LOL

Portfolio B included a total of 350 MW of short-term thermal PPAs and Zonal Resource Credits ("ZRCs"), 2,600 MW of combined cycle capacity (1,300 MW through 2029), 1,882 MW of new storage capacity (1,227 MW through 2029), 1,850 MW of wind, and 675 MW of solar over the twenty-year study period. Relative to Portfolio A, Portfolio B included additional near-term storage capacity to meet near-term capacity accreditation needs under the D-LOL construct and fewer long-term solar additions. Figure 9-3Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio B.

Figure 9-3: Portfolio B – Annual Resource Additions (Nameplate MW)

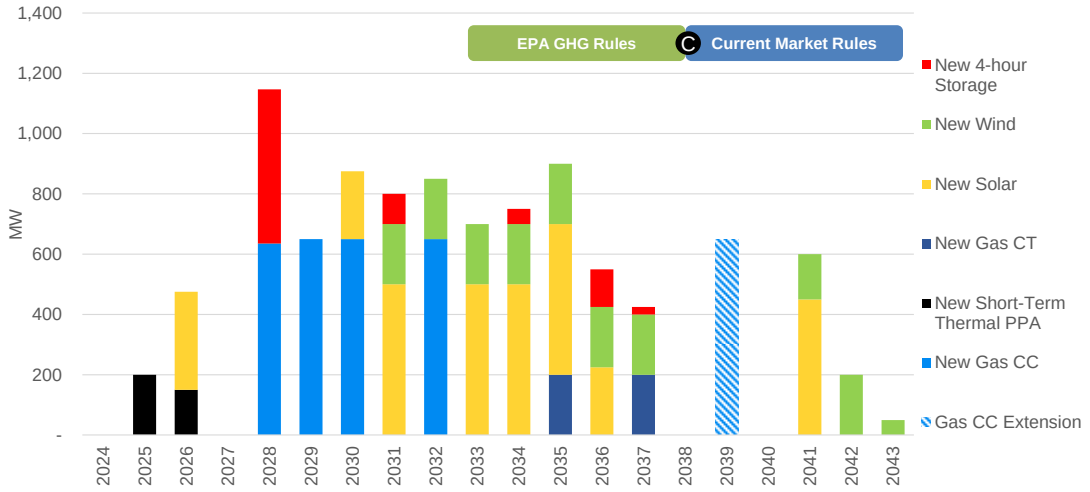


Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

9.1.3.3 Portfolio C – EPA GHG Rules and Current Market Rules

Portfolio C included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,585 MW of combined cycle capacity (1,285 MW through 2029), 400 MW of natural gas peaking capacity, 811 MW of new storage capacity (511 MW through 2029), 1,800 MW of wind, and 3,235 MW of solar (335 MW through 2029) over the twenty-year study period. Relative to the No EPA GHG constraints portfolios, Portfolio C included significantly more solar additions as a result of the EPA rules combined with more favorable capacity accreditation than what is assumed under the D-LOL construct. Figure 9-4 provides a summary of the annual nameplate capacity resource additions for Portfolio C.

Figure 9-4: Portfolio C – Annual Resource Additions (Nameplate MW)

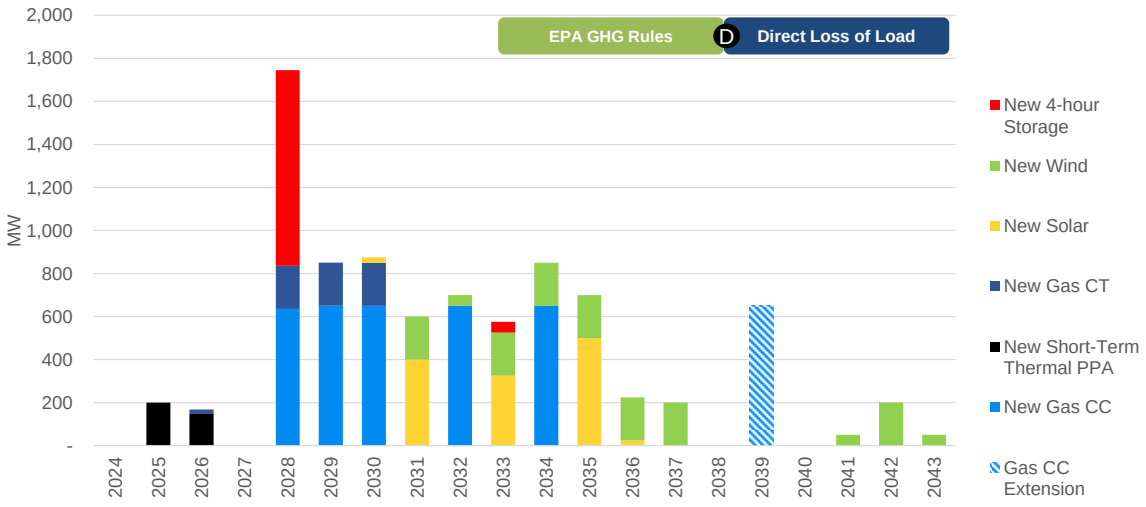


Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

9.1.3.4 Portfolio D – EPA GHG Rules and D-LOL

Portfolio D included a total of 350 MW of short-term thermal PPAs and ZRCs, 3,235 MW of combined cycle capacity (1,285 MW through 2029), 618 MW of natural gas peaking capacity, (418 MW through 2029), 959 MW of new storage capacity (909 MW through 2029), 1,550 MW of wind, and 1,275 MW of solar over the twenty-year study period. Relative to Portfolio C, Portfolio D included additional near-term storage and natural gas peaking capacity to meet near-term capacity accreditation needs under the D-LOL construct. Figure 9-5Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio D.

Figure 9-5: Portfolio D – Annual Resource Additions (Nameplate MW)

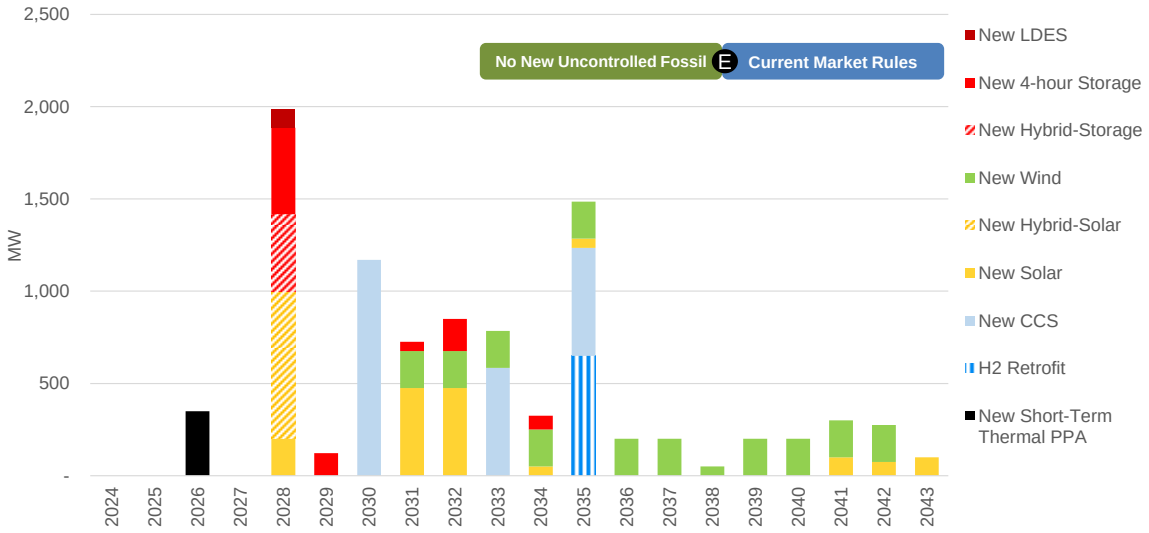


Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

9.1.3.5 Portfolio E – No New Uncontrolled Fossil and Current Market Rules

Portfolio E included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,340 MW of combined cycle capacity with CCUS in 2030 and beyond, 1,409 MW of new storage capacity (1,109 MW through 2029), 2,250 MW of wind, and 2,322 MW (997 MW through 2029) of solar over the twenty-year study period.[163] Relative to the other portfolios, Portfolio E included significant solar and storage through 2029 to meet growing energy needs without availability of new thermal resources without environmental controls until 2030 and beyond. Figure 9-6 provides a summary of the annual nameplate capacity resource additions for Portfolio E.

Figure 9-6: Portfolio E – Annual Resource Additions (Nameplate MW)



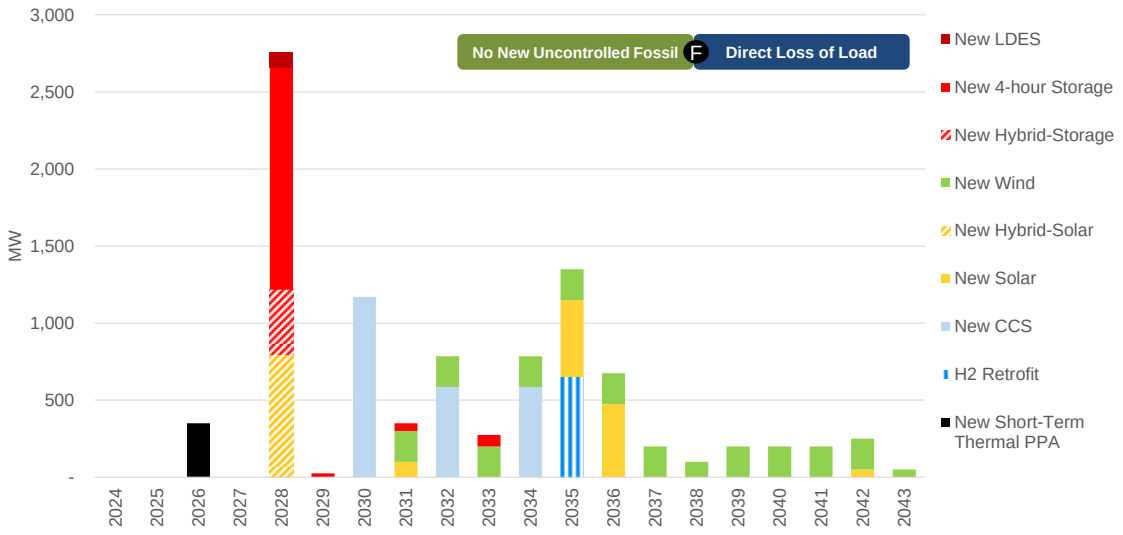
Note: There are two short-term PPAs in 2026. 200 MW lasts from 2026-2029. and 150 MW lasts from 2026-2030.

9.1.3.6 Portfolio F – No New Uncontrolled Fossil and D-LOL

Portfolio F included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,340 MW of combined cycle capacity with CCUS in 2030 and beyond, 2,111 MW of new storage capacity (1,986 MW through 2029), 2,350 MW of wind, and 1,922 MW (797 MW through 2029) of solar over the twenty-year study period. Relative to the Portfolio E, Portfolio F included significantly more near-term storage additions to meet near-term capacity accreditation needs under the D-LOL construct. Figure 9-7 provides a summary of the annual nameplate capacity resource additions for Portfolio F.

[163] Note that both Portfolio E and Portfolio F included the assumed conversion of NIPSCO's existing Sugar Creek combined cycle facility to burn high blends of hydrogen fuel, starting in 2035. See Section 4 for additional information on hydrogen fuel cost assumptions.

Figure 9-7: Portfolio F – Annual Resource Additions (Nameplate MW)



Note: There are two short-term PPAs in 2026. 200 MW lasts from 2026-2029, and 150 MW lasts from 2026-2030.
**Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.*

9.1.4 Additional Portfolio Variants

After the development of Portfolios A-F, NIPSCO identified the need to develop two additional portfolio concepts to assess potential portfolio variants that would allow new fossil resource additions without emission controls at the initial construction in the near-term, but still achieve net zero by 2040. These variants included:

- Portfolio "D_CCUS"
  - Preserved the optimized expansion plan from original inputs and constraints.
  - Assumed future CCUS retrofit on up to 2,000 MW of new combined cycle capacity over the 2035-2037 time period.
  - Assumed remaining combined cycle capacity is retrofit to burn up to 100% hydrogen over the long-term.
- Portfolio "D_H2"
  - Preserved optimized expansion plan from original inputs and constraints.
  - Assumed all combined cycle capacity is retrofit to burn up to 100% hydrogen over the long-term.

Figure 9-8 illustrates the cumulative new capacity additions for all six portfolio concepts (A-F) plus the additional "D variants" through 2043, while Figure 9-9 shows the projected energy mix for the eight portfolios in the same year in the Reference Case.

Figure 9-8: Resource Additions across all Portfolios – Cumulative Nameplate Capacity through 2043

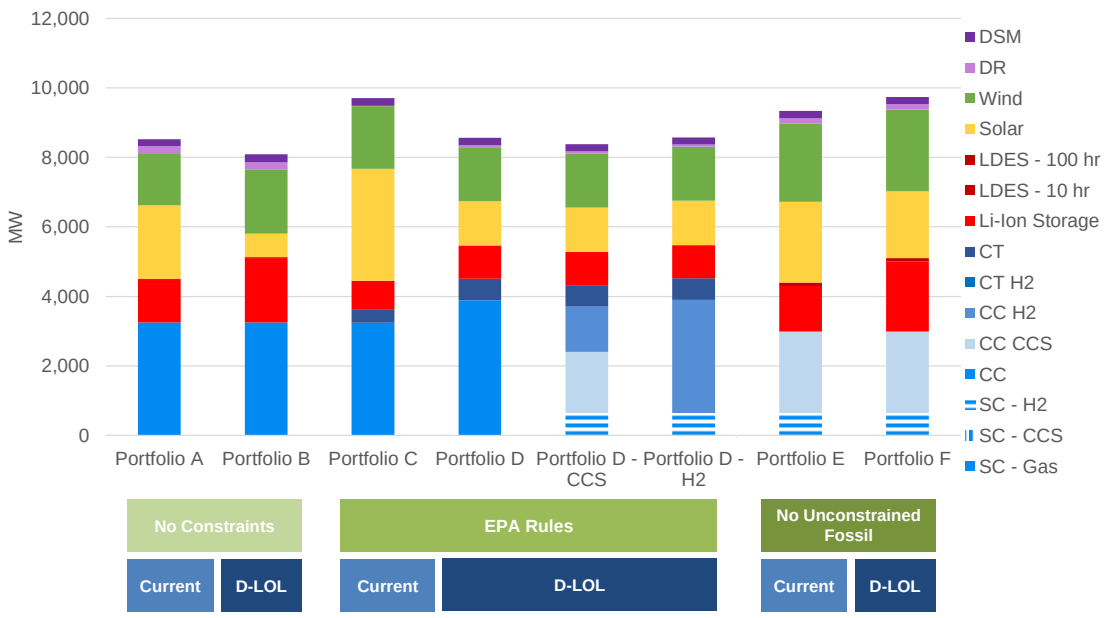
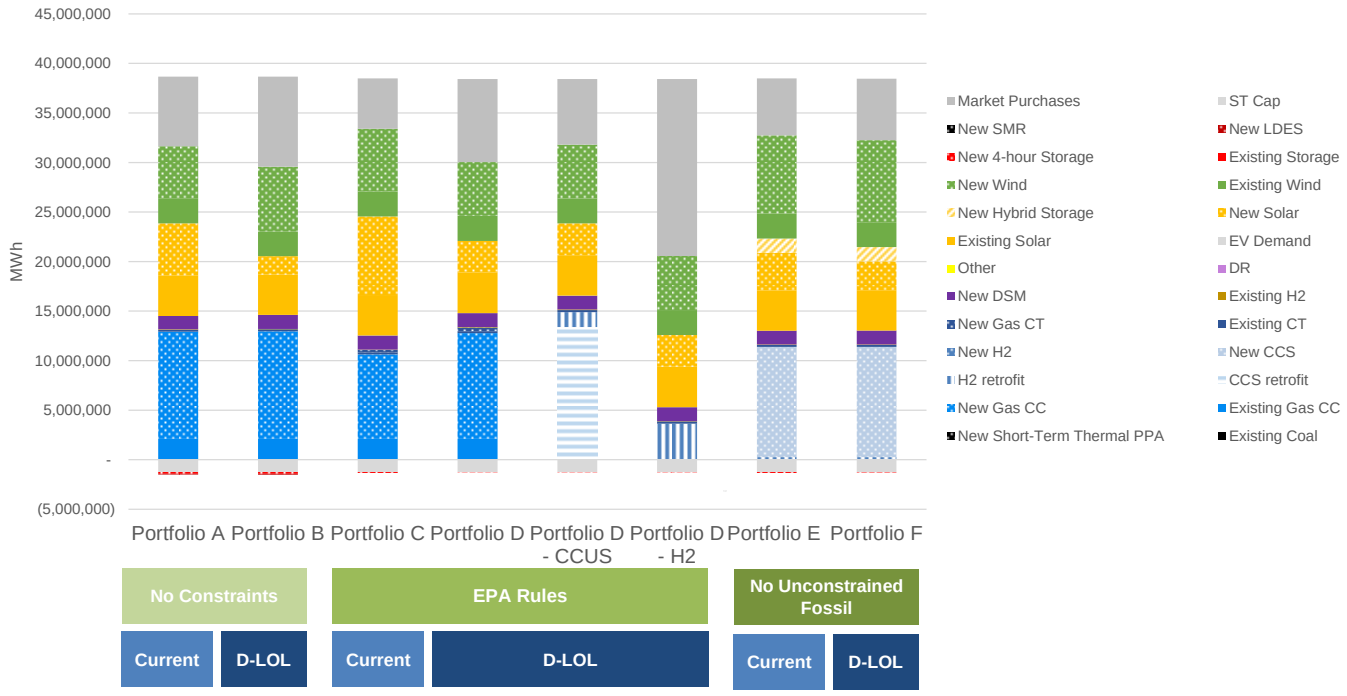


Figure 9-9: Projected Energy Mix across All Portfolios – 2043



9.1.5 DSM Program Selection

As described in detail in Section 5, NIPSCO's portfolio optimization analysis incorporated EE and DR bundles for selection. Overall, most EE bundles were selected across the portfolios. In particular, the Low/Medium cost Residential and Commercial and Industrial bundles were nearly always selected across all planning periods. However, the high Residential and Behavioral bundles were observed to be more marginal, but still selected across many years and portfolios. In general, more EE was selected in Portfolios C, D, E, and F relative to Portfolios A and B. This is primarily a result of greater energy savings need under conditions when the EPA GHG Rules and their consequent limits on new combined cycle capacity factors are in place. A full summary of EE selection by program bundle and time period across all portfolios is summarized in Figure 9-10.

Figure 9-10: Energy Efficiency Selection across Portfolios

Program	Portfolio A			Portfolio B			Portfolio C			Portfolio D			Portfolio E			Portfolio F		
	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46
Res (Low/Med)	o	X	X	o	X	X	o	o	X	X	X	X	X	X	X	X	X	X
Res (High)	o	o	o	o	X	X	X	o	X	X	X	o	o	o	o	X	X	o
Res (Behavioral)	o	o	X	X	o	X	X	X	X	X	X	X	X	o	X	o	X	X
C&I	o	X	X	o	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQW	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQHear	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

X = Selected
o = Not Selected

On the DR side, the Behavioral, data center, C&I, and dynamic rates programs were most often selected across portfolios. The thermostat program was selected in Portfolios A and B, while the water heater, EV managed charging, and BTM storage programs were not selected at all. In general, less DR was selected in Portfolios C and D relative to the others, given greater amounts of alternative resources needed for both energy and capacity needs in those portfolios. A full summary of DR selection by program bundle across all portfolios is summarized in Figure 9-11.

Figure 9-11: Demand Response Selection across Portfolios

Program	Portfolio A	Portfolio B	Portfolio C	Portfolio D	Portfolio E	Portfolio F
RAP Thermostats	X	X	O	O	O	O
RAP Water Heaters	O	O	O	O	O	O
RAP Behavioral	X	X	X	X	X	X
RAP Dynamic Rates	X	X	O	O	X	X
RAP EV Managed Charging	O	O	O	O	O	O
RAP BTM Storage	O	O	O	O	O	O
RAP C&I	X	X	O	O	X	X
RAP Data Center	X	X	O	X	X	X

X = Selected
O = Not Selected

Overall, Figure 9-12 summarizes the nameplate capacity additions and other resource additions and changes for all of the portfolios through 2043.

Figure 9-12: Summary of Incremental Resource Additions across Portfolios

	A	B	C	D (all)	E	F
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	Late 2030s	At Start-up	At Start-up
Wind	1,500	1,850	1,800	1,550	2,250	2,350
Solar	2,125	675	3,225	1,275	2,322	1,922
Storage[1]	1,250	1,885	811	959	1,410	2,111
Gas CCGT	2,600	2,600	2,588	3,240		
Gas Peaking			400	620		
Gas CCGT w/CCUS					2,340	2,340
Sugar Creek	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DR / DSM[2]	400	430	230	270	365	365
Total ICAP Additions (excl. DSM/DR)	7,475 MW	7,010 MW	8,824 MW	7,641 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer)	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

[1] *Includes both 4-hour Lithium-ion and long-duration storage*
[2] *DR/DSM additions calculated as peak capacity contribution in summer of 2043*

9.2 Portfolio Evaluation – Scorecard Metrics

In order to evaluate the performance of the eight portfolios, NIPSCO developed a scorecard of objectives, indicators, and key metrics. As illustrated in Figure 9-13, these objectives and metrics included:

- Cost to customer metrics associated with the NPVRR over 10- and 30-year time periods under Reference Case conditions.
- Risk metrics associated with cost certainty across scenarios and across the distribution of stochastic uncertainty variables: cost risk was measured at the 95th percentile and lower cost opportunity was measured at the 5th percentile.
- Environmental sustainability was measured with the carbon emission intensity of the portfolio over the 2024-2040 time period.
- Reliability was measured through a probabilistic risk assessment to measure "forced market exposure" risk and via reporting of the amount of new capacity in the portfolio able to respond within 30 minutes.
- Positive social and local economic impacts were measured through tracking the net present value of property taxes paid as a result of the generation portfolios.

Figure 9-13: Scorecard Metrics

Objectives	Indicators	Metrics
Affordability	**Cost to Customer**	• Near-term and long-term Impact to customer bills • Metric: 10-year and 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: 95th%-50th% cost risk from probabilistic analysis
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: 50th%-5th% cost risk from probabilistic analysis
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions / cumulative generation (2024-40 short tons/MWh of CO2)
Reliable, Flexible, and Resilient Supply	**Reliability, Flexibility**	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: Loss of Load Expectation proxy ("Forced market exposure") metrics for NIPSCO system from probabilistic reliability analysis • Metric: Capacity able to respond within 30 mins
Positive Social, & Economic Impacts	**Local Investment in Economy**	• The effect on the local economy from new projects and ongoing property taxes and targeted investment • Metric: NPV of property taxes from the entire portfolio

9.3 Portfolio Evaluation – Analysis Results

9.3.1 Reference Case Customer Cost Results

The eight portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail) to estimate revenue requirements for each over time. The assessment was first performed across the Reference Case set of market assumptions and inputs to calculate baseline projections of the NPVRR over the thirty-year planning horizon, which are summarized in Figure 9-14. Key observations under the Reference Case market conditions include:

- Implementation of D-LOL will likely drive more capacity additions and raise portfolio costs. Over the 30-year NPVRR period, portfolio costs are projected to be ~$450-500 million higher in Portfolios B and D relative to A and C; a similar cost increase is evident over the initial 10 years of the study period as well, due to additional near-term capacity needs.

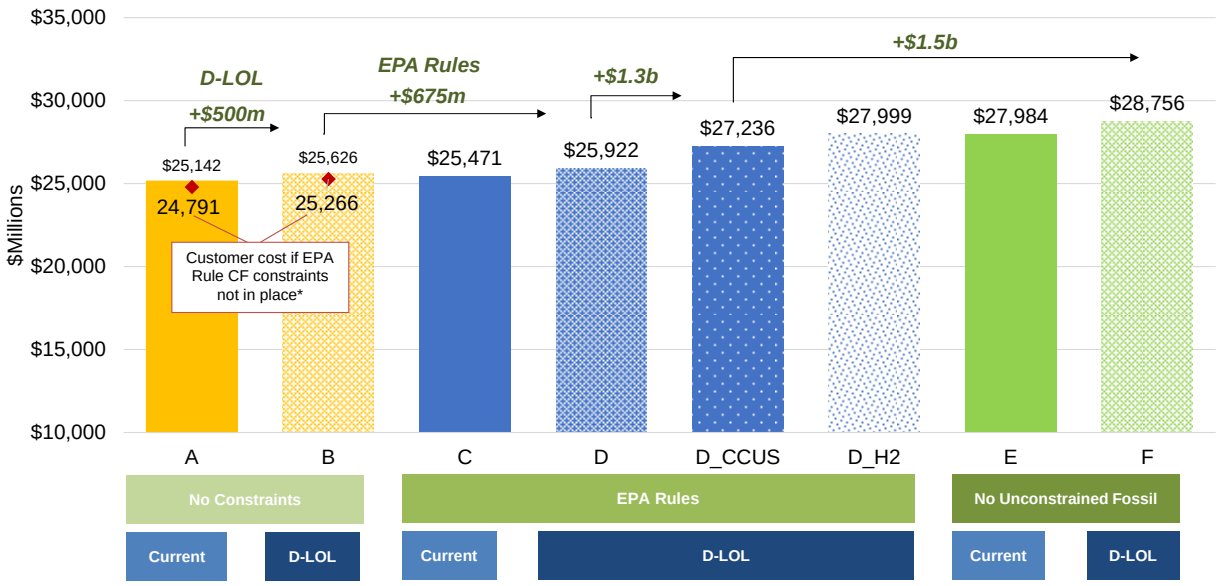
- Customer costs are projected to be higher in Portfolios C/D relative to Portfolios A/B due to new EPA GHG rules. The level of cost premium is around $675 million in NPVRR assuming no constraints on combined cycle operation under Reference Case market conditions. If the optimized portfolios were held to the 40% capacity factor constraints, available energy market purchases would still result in lower costs for A and B relative to C and D.

- With the assumed load growth, a cost premium is associated with meeting net zero goals and restricting new fossil resources to only those with emission controls. Assuming no technology cost and performance risk with CCUS and assuming full monetization of all 45Q tax credits:

    - There is a ~$1.3 billion 30-year NPVRR premium associated with meeting NIPSCO's 2040 net zero goal with CCUS and H2 relative to continuing to operate Portfolio D with combined cycle additions and no subsequent retrofits.

    - There is an incremental ~$1.5 billion 30-year NPVRR premium associated with restricting new fossil resources to only those with emission controls (Portfolio F). Over the first 10 years, the incremental NPVRR impact is about $300 million.

Figure 9-14: Reference Case Cost to Customer (30-year NPVRR – millions of $)



9.3.2 Scenario Customer Cost Results

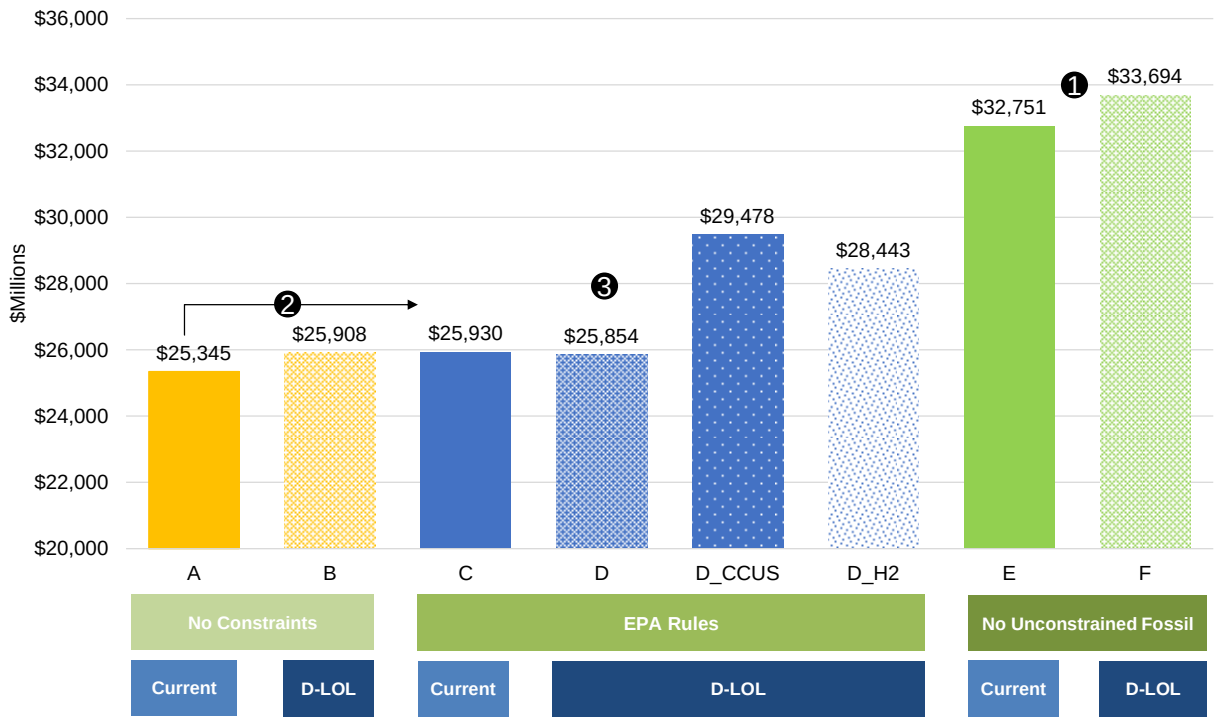
In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each portfolio against each scenario, as described earlier in Section 8. Under the Slower Transition scenario, relative to the Reference Case, as shown in Figure 9-15:

1. Costs for Portfolios that rely heavily on federal tax credits for significant clean energy additions (E, F, and D_CCUS) face the largest cost increases.

2. The premium associated with Portfolio C (developed under EPA Rule constraints) relative to Portfolio A decreases when both portfolios are not subject to capacity factor constraints.

3. Portfolio D (with an additional CCGT built under D-LOL) is lower cost than Portfolio C, given no constraints on capacity factor and lower gas prices.

Figure 9-15: Slower Transition Scenario Cost to Customer (30-year NPVRR – millions of $)



Under the Domestic Resiliency scenario, relative to the Reference Case, as shown in Figure 9-16:

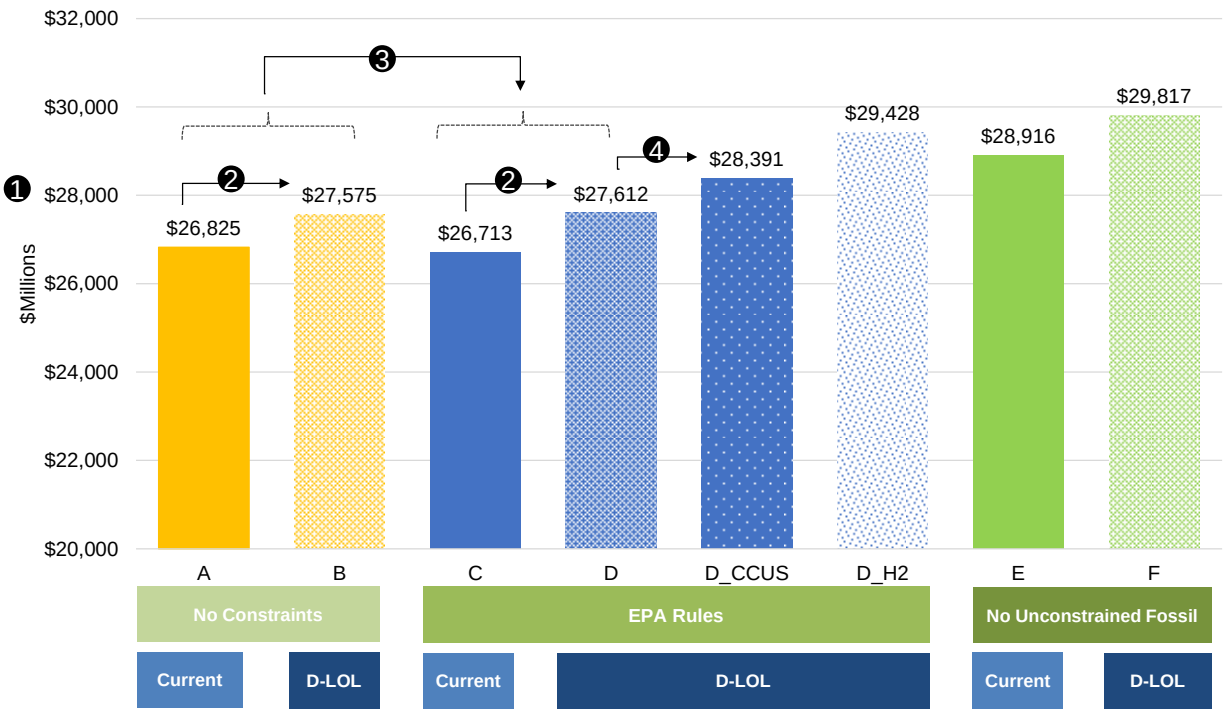
1. Overall portfolio costs are higher, driven by elevated natural gas and power prices.

2. There is a greater premium associated with D-LOL portfolios, as they have fewer renewable additions and are more exposed to higher gas and power prices.

3. The cost premium for portfolios constructed under EPA Rules (Portfolios C/D) is lower, as the cost of market purchases for Portfolios A/B is higher. Portfolio C is lower cost than A.

4. The cost premium for Portfolio D_CCUS relative to Portfolio D is lower, as higher MISO prices advantage high CCUS capacity factors relative to CCGT capped at 40% CF.

Figure 9-16: Domestic Resiliency Scenario Cost to Customer (30-year NPVRR – millions of $)



Under the Aggressive Environmental Regulation scenario, relative to the Reference Case, as shown in Figure 9-17:

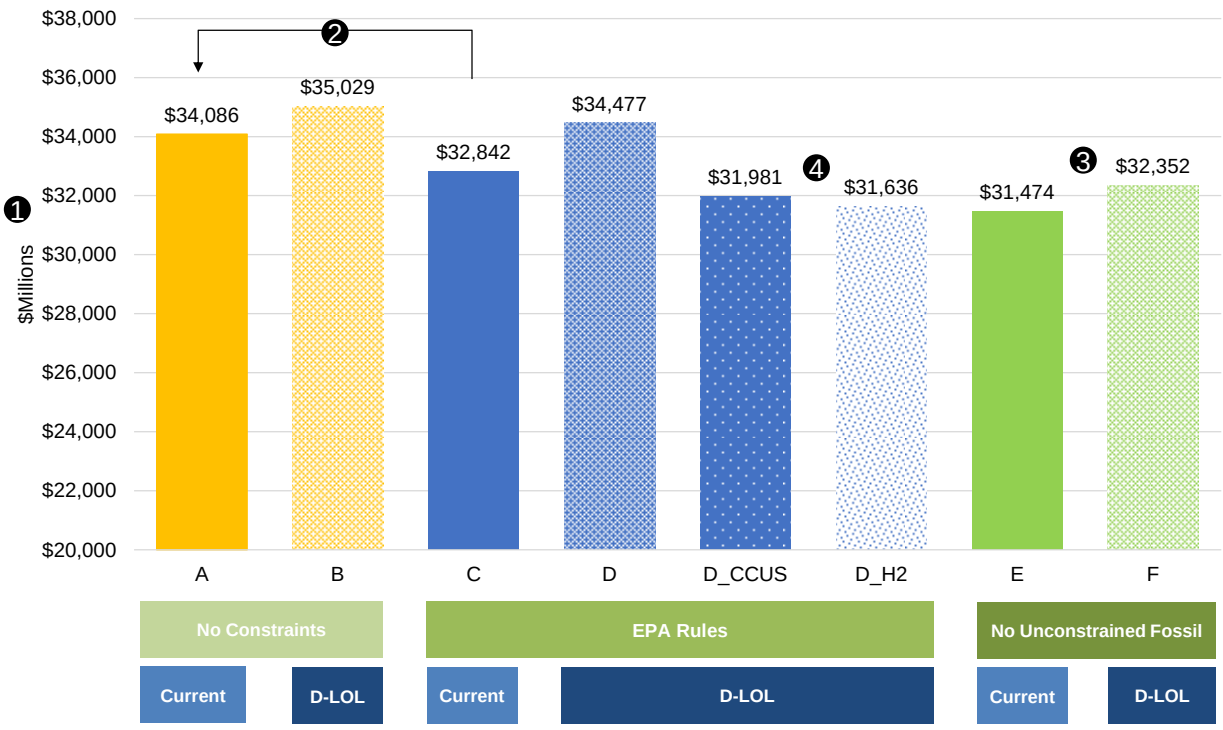
1. Overall portfolio costs are significantly higher, driven by higher natural gas prices and implementation of a CO2 price.

2. Costs for portfolios optimized without EPA Rules are higher than those optimized with the rules in place: Portfolio A/B higher cost than Portfolio C/D.

3. Portfolios E and F are lower cost than Portfolios A/B and Portfolios C/D due to the high CO2 price in the AER scenario.

4. Hydrogen optionality lowers long term costs for the Portfolio D variants when natural gas and carbon prices are high. Both are lower cost than Portfolio F.

Figure 9-17: Aggressive Environmental Regulation Scenario Cost to Customer (30-year NPVRR – millions of $)

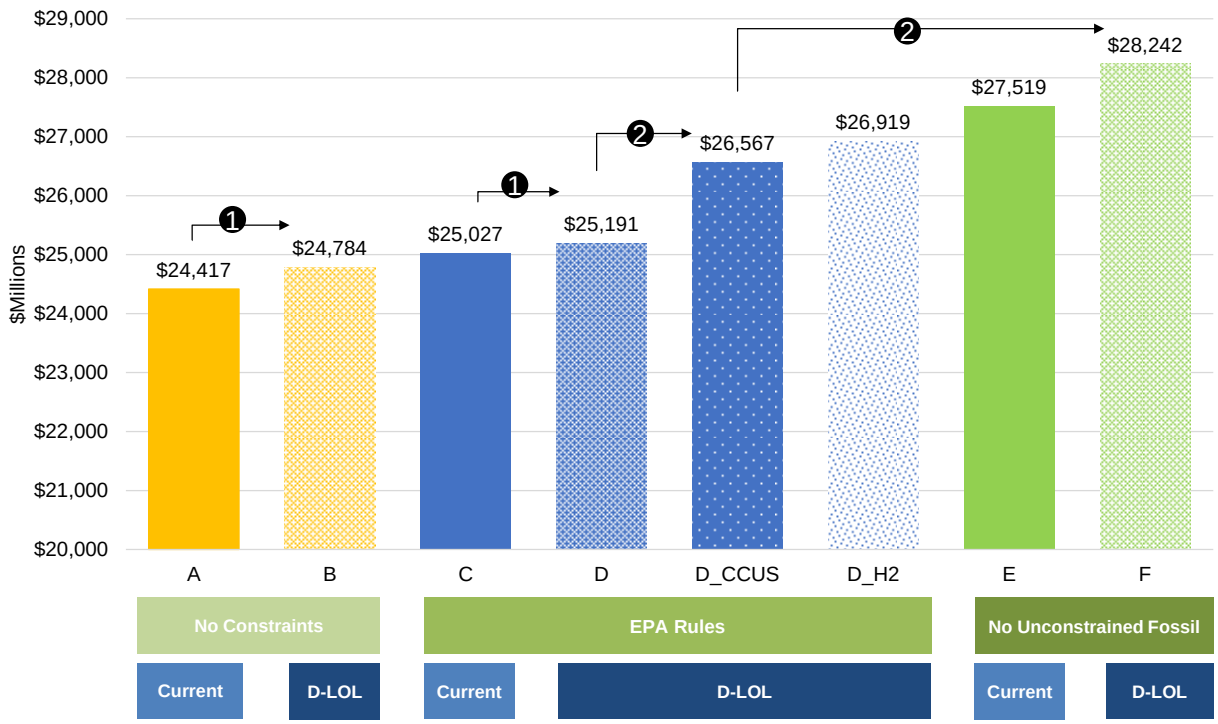


Under the Accelerated Innovation scenario, relative to the Reference Case, as shown in Figure 9-18:

1. Higher overall load growth increases costs for portfolios with fewer capacity additions (Portfolio A and Portfolio C) relative to those with more (Portfolio B and Portfolio D), and the "D-LOL premium" is narrower.

2. Lower long-term natural gas prices slightly increase the premium associated with the portfolios that move towards net zero by 2040.

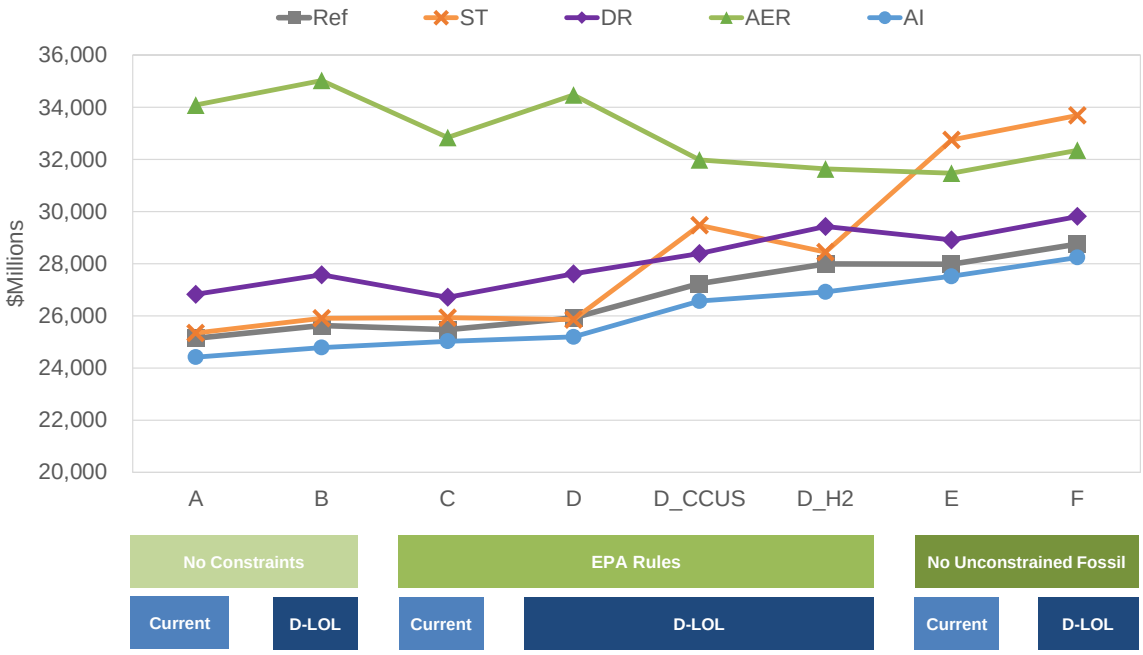
Figure 9-18: Accelerated Innovation Scenario Cost to Customer (30-year NPVRR – millions of $)



Overall, across scenarios, as illustrated in Figure 9-19, the following key observations were made:

- Portfolios A, B, C, and D are generally lower cost than the D Variants and Portfolios E and F. However, since they do not control long-term CO2 emissions, Portfolios A, B, C, and D are the highest cost in the AER scenario, which has a high carbon price.
- Portfolios relying heavily on near-to-mid-term tax credits (particularly Portfolios E and F) have the highest cost premium in the Slower Transition scenario.
- The optionality to phase-in CO2 control technologies embedded in Portfolio D_CCUS and Portfolio D_H2 results in a low scenario range.

Figure 9-19: NPVRR Summary across Scenarios



9.3.3 Stochastic Analysis Results

In addition to assessing each portfolio against each market scenario, NIPSCO also evaluated the six portfolios against the full stochastic distribution of potential outcomes for commodity prices (fuel and MISO power prices), NIPSCO load, wind and solar output, and thermal resource outages, as described in more detail in Section 8. The stochastic assessment was used to further evaluate the risk of each of the portfolios and produce key outputs within two scorecard categories:

- **Reliability** – An evaluation of "forced market exposure" risk was performed to assess the likelihood of NIPSCO having insufficient native resources to meet load at any given point time, thus resulting in forced exposure to the MISO market.
- **Rate stability** – An assessment of the portfolios' cost risk associated with the 95th percentile of the cost distribution and the lower cost opportunity associated with the 5th percentile of the cost distribution.

9.3.3.1 Forced Market Exposure Risk

Forced market exposure risk is calculated by comparing NIPSCO's available resources to NIPSCO's load obligation across every hour of the sample study year (2030) and across all 1,000 iterations of stochastic inputs that were developed. The risk can be visualized by assessing the long or short position of the portfolio at various percentiles across the distribution and at various times of day and across the year. This is illustrated in Figure 9-20, Figure 9-21, and Figure 9-22 for the six portfolios at the 90th percentile.

Figure 9-20: 90th Percentile of Forced Market Exposure - Portfolios A and B

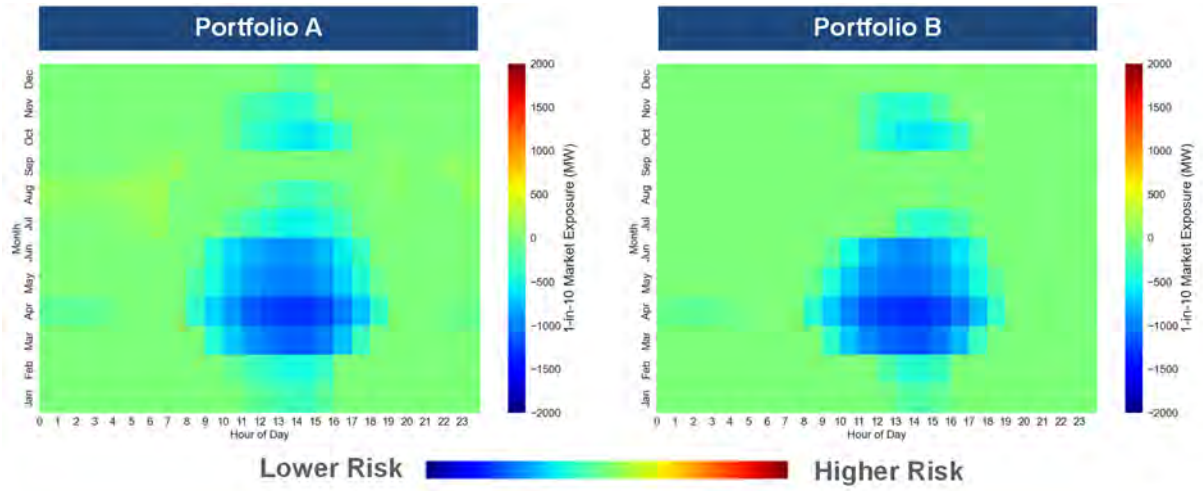


Figure 9-21: 90th Percentile of Forced Market Exposure - Portfolios C and D

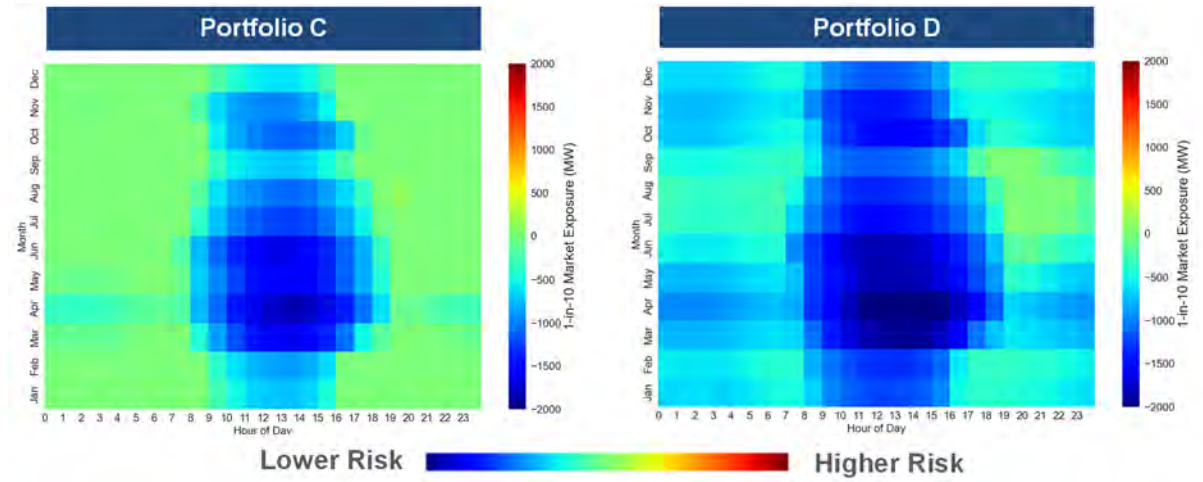
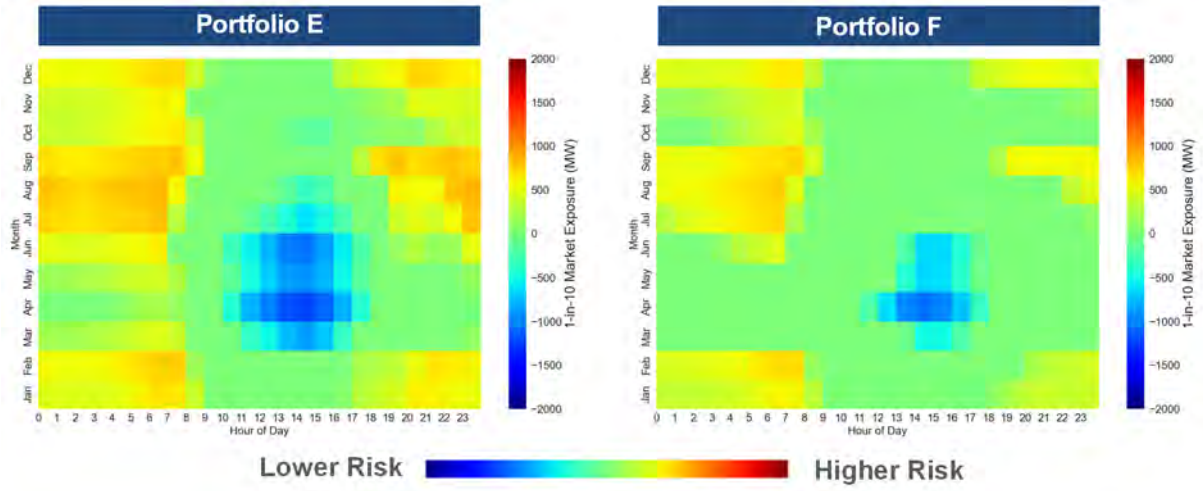


Figure 9-22: 90th Percentile of Forced Market Exposure - Portfolios E and F



These illustrations depict a "1-in-10" level event (i.e., only 10% of the simulated events during that month and hour exceed the reported level of forced market exposure). The magnitude of forced market exposure is also reported in Figure 9-23 as a measure of the expected amount of energy each year for which NIPSCO would be forced to purchase from the market, regardless of economic dispatch decisions. The percentage of expected forced market purchases is also reported by normalizing the expected forced market purchases by the total system energy sales.

In these graphics, a negative number (shown in blue colors with a greater long position shown with a darker shade) represents an event when the NIPSCO portfolio is long on capacity and has the option to operate economically by buying from the market or dispatch its own resources based on what is the lowest cost option for customers. A positive number (shown in orange and red with a darker red representing a greater short position) represents an event when NIPSCO would be *forced* to purchase from the market, no matter the cost or tightness of the broader MISO system at that time. If these periods of forced market exposure coincide with periods of stress in the broader MISO market, the event could result in a loss of load event if there is not sufficient energy on the market to cover NIPSCO's native shortfall.

Overall, Portfolios E and F are at risk of experiencing the most significant forced market exposure, amounting to between 2-3% of total MWh served in 2030, as summarized in Figure 9-23. The D Portfolios are in the strongest position to mitigate against forced market exposure risk and be "in control of their own destiny." Only a small portion of the total MWh served would be forced to be purchased from the market.

Figure 9-23: Reliability Scorecard Metric – Forced Market Exposure

Portfolio	Forced Market Exposure – Expected Value (GWh)	Forced Market Exposure Relative to Total Load (%)
A	235	0.91
B	86	0.33
C	89	0.34
D (all variants)	4	0.02
E	793	3.08
F	515	2.00

9.3.3.2 Cost Risk

Cost risk is calculated by evaluating the uncertainty in NIPSCO's portfolio costs across the distribution of stochastic variables, including those evaluated in the forced market exposure risk analysis plus natural gas prices and MISO market power prices. To assess cost risk in a representative year (2030), NIPSCO down-sampled 100 iterations from the overall distribution of

one thousand iterations from the forced market exposure risk analysis. This smaller sub-set of samples was selected as representative of the entire distribution, and using a smaller number of scenarios substantially reduces the required amount of computer run-time while still providing a robust overview of the stochastic risk posed to each of NIPSCO's portfolio options. This representative set of 100 samples was run through the Aurora portfolio model to simulate dispatch against different generator forced outages, wind generation, solar generation, electricity price, and natural gas price outcomes. In this manner, NIPSCO was able to evaluate the variable cost exposure for the different portfolios and provide a unified analysis between the stochastic market exposure analysis and the production cost modeling in Aurora.

To find this smaller sub-set, a clustering analysis was performed on the average annual electricity price, natural gas price, and net load across the entire collection of stochastic iterations to divide the population into representative samples which span the range of possible outcomes. Each of the 1000 samples was assigned to one of the 100 clusters. A random choice was selected from each of these clusters. The resulting sub-set of 100 iterations provides a sound representation of the types of random shocks that NIPSCO might experience (i.e., higher/lower than expected net load or higher/lower than expected commodity prices).

For each of these representative 100 samples, NIPSCO performed a production cost model simulation, which dispatched the portfolio resources using the wind generation, solar generation, demand, market electricity price, and natural gas price from that stochastic iteration. The resulting 100 outcomes represent the range of possible all-in costs that can be incurred by each portfolio, depending on the randomness of possible events. The 95th and 5th percentile cost outcomes were reported as the range of possible cost outcomes.

Overall, the magnitude of cost distributions across portfolios is narrower than the scenario range, suggesting that stochastic risk for these portfolio options is less impactful than the major policy or market shifts evaluated across scenarios. However, the stochastic analysis results do indicate that for the 2030 sample year that was evaluated, Portfolios A through D have broader distributions of cost uncertainty overall (higher and lower) as a result of the impact of natural gas price uncertainty. Although Portfolios E and F have more comparable 75th percentile risk due to significant MISO market exposure, both have lower tail risk than Portfolios A through D. This is illustrated in Figure 9-24 and Figure 9-25, which summarize the rate stability metrics associated with NIPSCO's integrated scorecard.

As noted, natural gas price is a key driver to the all-in cost outcome. This is shown in Figure 9-26, which plots the annual average natural gas price across the 100 iterations evaluated in Aurora versus the annual impact on portfolio costs for Portfolio D relative to the median outcome. As natural gas prices increase, the variable cost of the portfolio also increases linearly, and a strong correlation between total costs and natural gas prices is evident. In fact, for Portfolio D, a $1 increase in natural gas price corresponds to an expected $125M increase in portfolio costs. Overall, natural gas prices show significant volatility within a year, and daily or monthly spikes are typically coupled with short-term market electricity price spikes, increasing the overall operating costs of the portfolios, especially those with higher levels of natural gas generation.

Figure 9-24: Distribution of Cost Risk across Portfolios – 2030, Normalized to the Median Cost

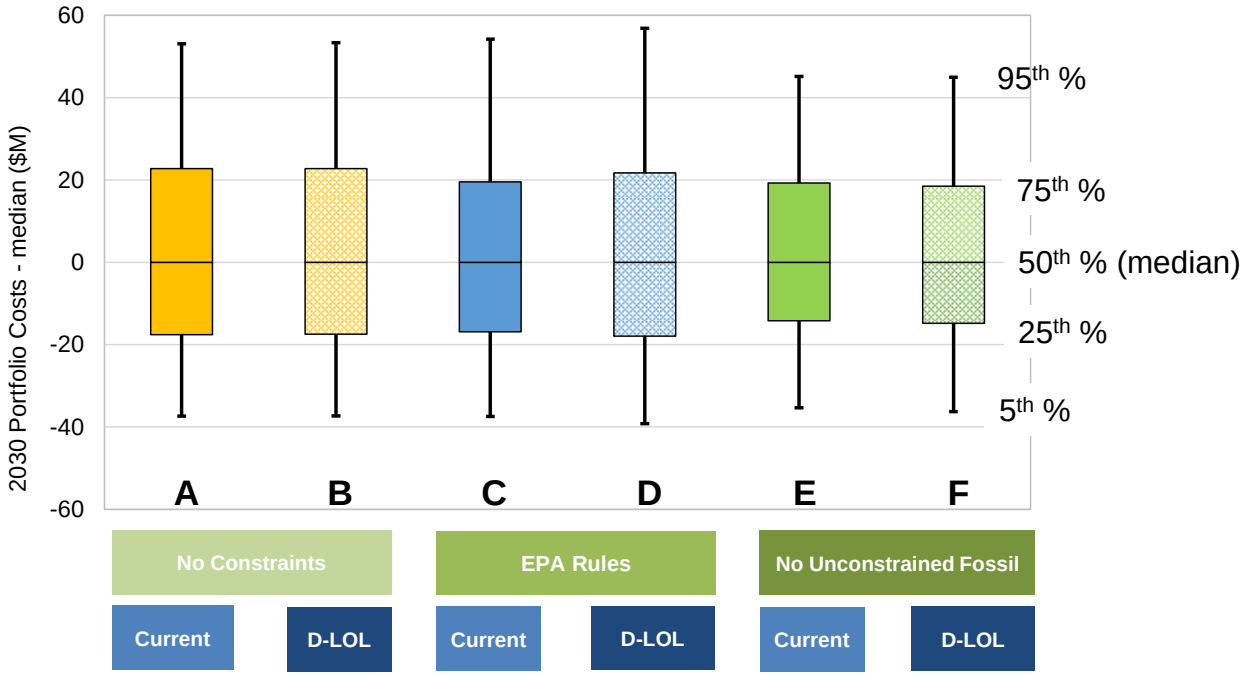
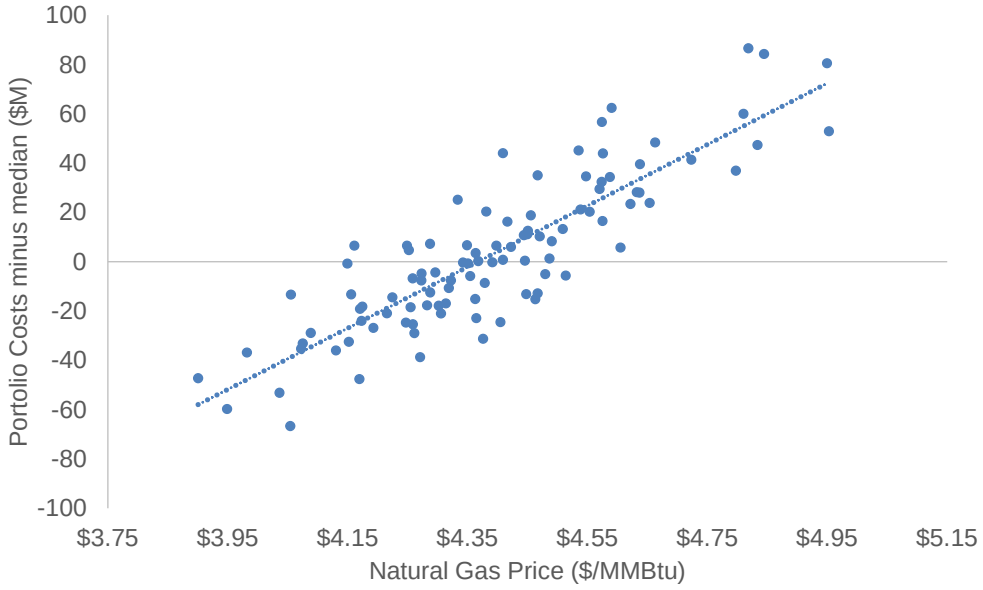


Figure 9-25: Rate Stability Scorecard Metric – Cost Risk and Low Cost Opportunity (millions of $)

Portfolio	50th Percentile *minus* 5th Percentile	75th Percentile *minus* 50th Percentile	95th Percentile *minus* 50th Percentile
A	37.4	22.8	53.1
B	37.3	22.7	53.3
C	37.4	19.5	54.2
D	39.2	21.7	56.8
E	35.4	19.2	45.1
F	36.3	18.5	45.0

Figure 9-26: Relationship between Annual Average Natural Gas Price and Annual Portfolio Cost across Stochastic Distribution (Portfolio D)



9.3.4 CO2 Emissions

NIPSCO tracked its projected CO2 emissions[164] for all portfolios relative to its historical emissions since its baseline accounting year of 2005, as illustrated in Figure 9-27. As shown, all portfolios that add uncontrolled new combined cycle resources towards the end of the 2020s and into the 2030s would be expected to realize increases in CO2 emissions, offsetting expected declines associated with the upcoming planned retirements of Schahfer Units 17 and 18 and Michigan City Unit 12. If the EPA GHG rules are not in place (Portfolios A and B),[165] CO2 emissions would be expected to remain between 6 and 7 million tons per year through the mid-2030s, with expected declines thereafter, as a result of lower anticipated economic dispatch for combined cycles in the MISO market. If the EPA GHG rules associated with capacity factor constraints for new combined cycles take effect in 2032 (Portfolios C and D), emissions would be expected to fall closer to 5 million tons per year thereafter and through the study period.

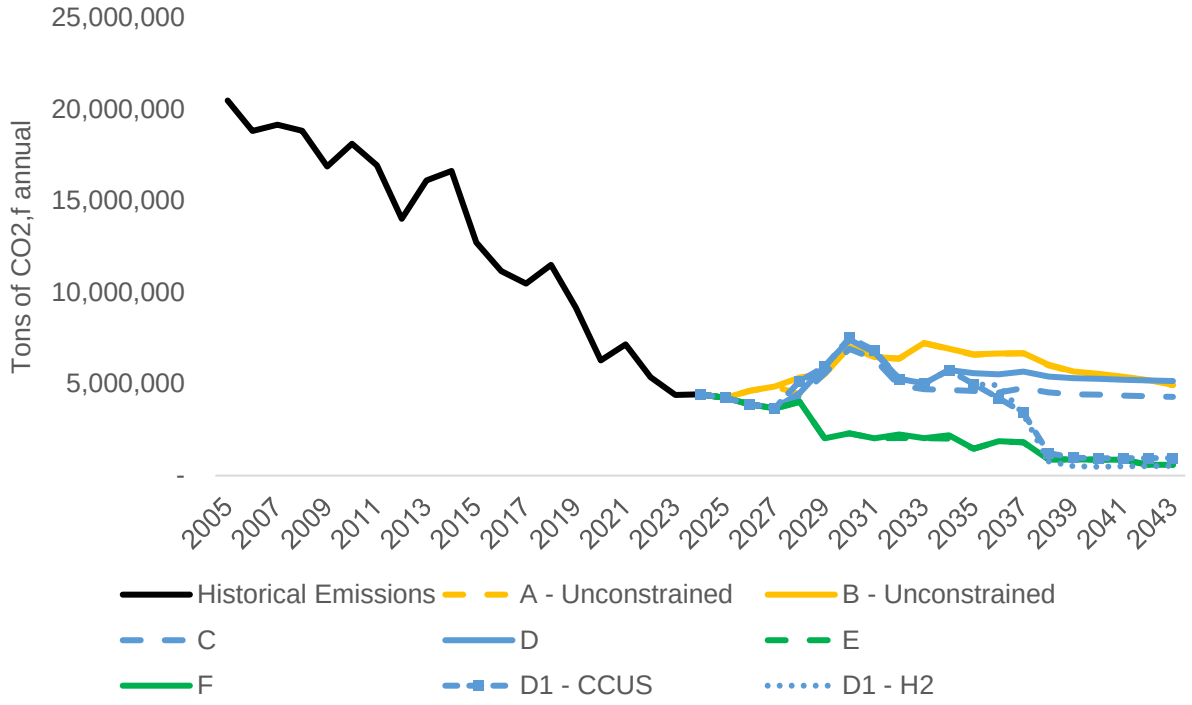
For portfolios that immediately control the emissions of new combined cycle capacity additions via CCUS (Portfolios E and F), annual emissions would be projected to fall to around 2 million tons per year after the retirement of Michigan City Unit 12, with potential additional reductions by the end of the 2030s associated with conversion of NIPSCO's existing Sugar Creek combined cycle to burn hydrogen. For the D variants (Portfolios D_CCUS and D_H2), emissions

164 NIPSCO's projected emissions include emissions from owned resources and contracted resources. The accounting does not include the impact of energy purchases and sales with the MISO market.

165 Note that all emission summaries are shown with Portfolios A and B not complying with EPA GHG rules even though certain scenarios evaluated their performance under these constraints.

controls implemented on combined cycle units in the mid-2030s would be expected to drive emissions towards the levels expected in Portfolios E and F by the end of the 2030s.

Figure 9-27: Annual CO2 Emission Projections for Portfolios



Given the significant load growth expected in NIPSCO's 2024 IRP, an emissions intensity metric was also developed, dividing the total tons of CO2 emissions by total MWh generated by the NIPSCO portfolio.[166] As shown in Figure 9-28, the emissions intensity of the portfolio is expected to decline from 2024 through 2043, with the largest declines associated with the portfolios that control emissions from combined cycle capacity (E, F, D_CCUS, and D_H2). Figure 9-29 summarizes both cumulative tons of CO2 and the emission intensity for the various portfolio options over the 2024-2040 period.

[166] Both the projected emissions and projected generation include owned and contracted resources.

Figure 9-28: Annual CO2 Emission Intensity Projections for Portfolios

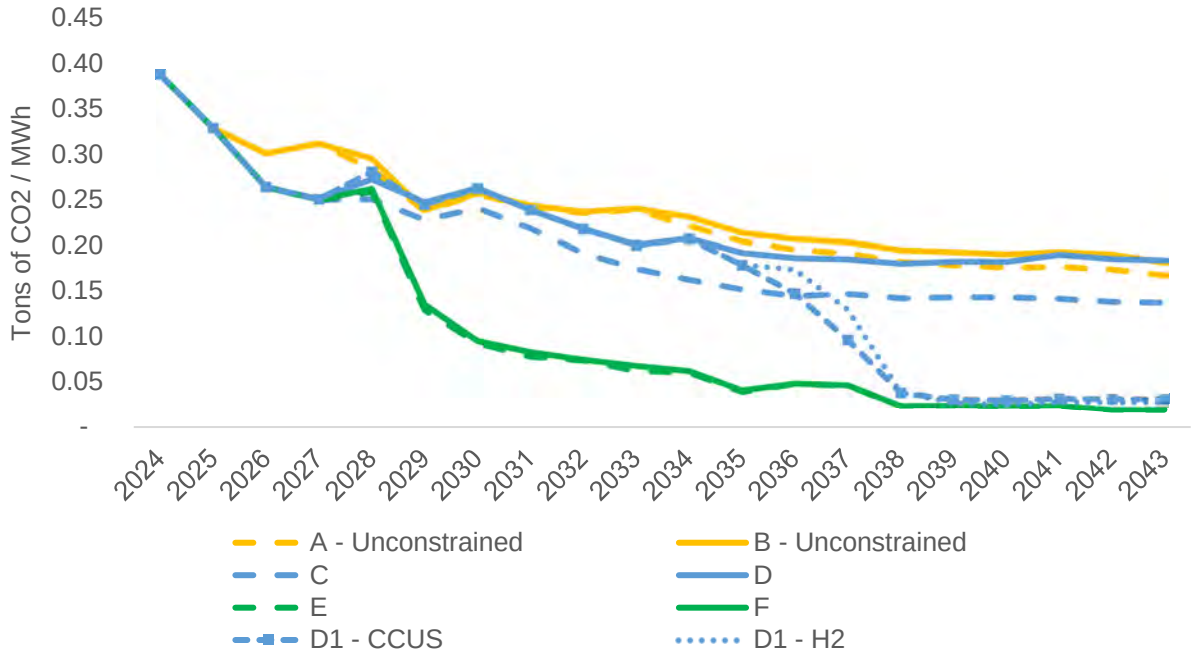


Figure 9-29: Total Emissions and Emission Intensity Average for 2024-2040

Portfolio	Cumulative Tons of CO2 (2024-2040)	Emission Intensity – tons/MWh (2024-2040)
A	99,172,714	0.23
B	100,300,258	0.24
C	80,942,519	0.19
D	89,701,019	0.22
D_CCUS	73,479,336	0.18
D_H2	72,713,688	0.20
E	40,444,963	0.09
F	40,817,177	0.09

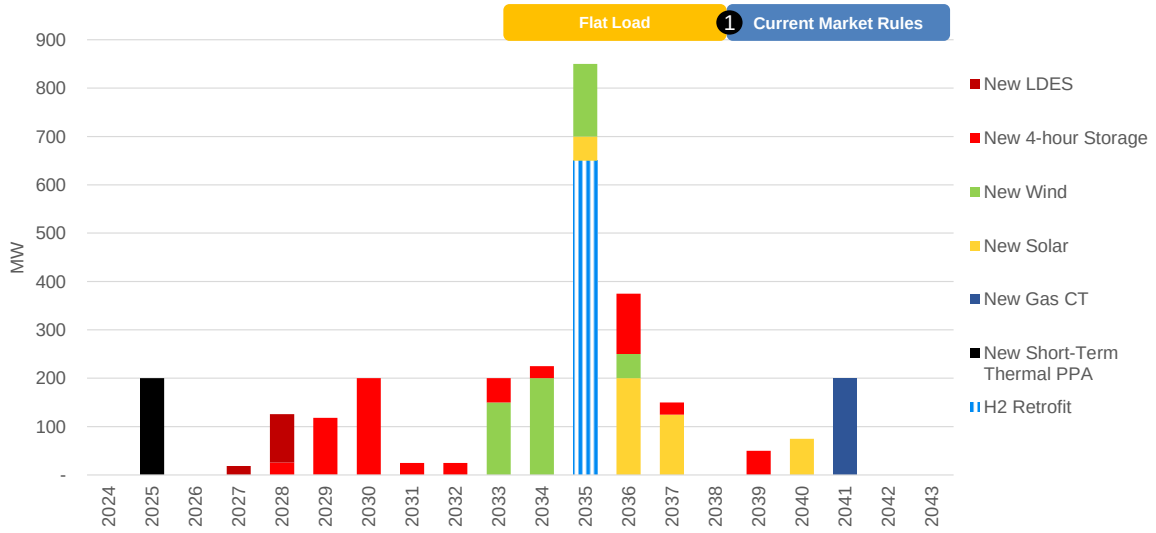
9.3.5 Sensitivity Analysis – Flat Load Growth

In addition to the portfolio evaluation under Reference Case load growth conditions, NIPSCO also performed portfolio optimization analysis under conditions without any new large load growth additions from data centers. "Flat load growth" portfolios were developed under the current market rules construct and under the D-LOL construct,[167] as summarized in the subsequent sections of this Section.

9.3.5.1 Flat Load 1 – Current Market Rules

The Flat Load 1 Portfolio included a total of 200 MW of short-term thermal PPAs and ZRCs, 200 MW of natural gas peaking capacity, 786 MW of new storage capacity (261 MW through 2029), 550 MW of wind, and 450 MW of solar over the twenty-year study period. In addition, the portfolio included all EE programs except for first tranche of C&I (2027-2029) and the Residential High and Behavioral programs. All DR programs were selected except for Water Heaters, EV Charging, and BTM Storage. Figure 9-30 provides a summary of the annual nameplate capacity resource additions for the Flat Load 1 Portfolio.[168]

Figure 9-30: Flat Load Portfolio 1 – Annual Resource Additions (Nameplate MW)



Note: The 2025 short-term PPA lasts through 2029.

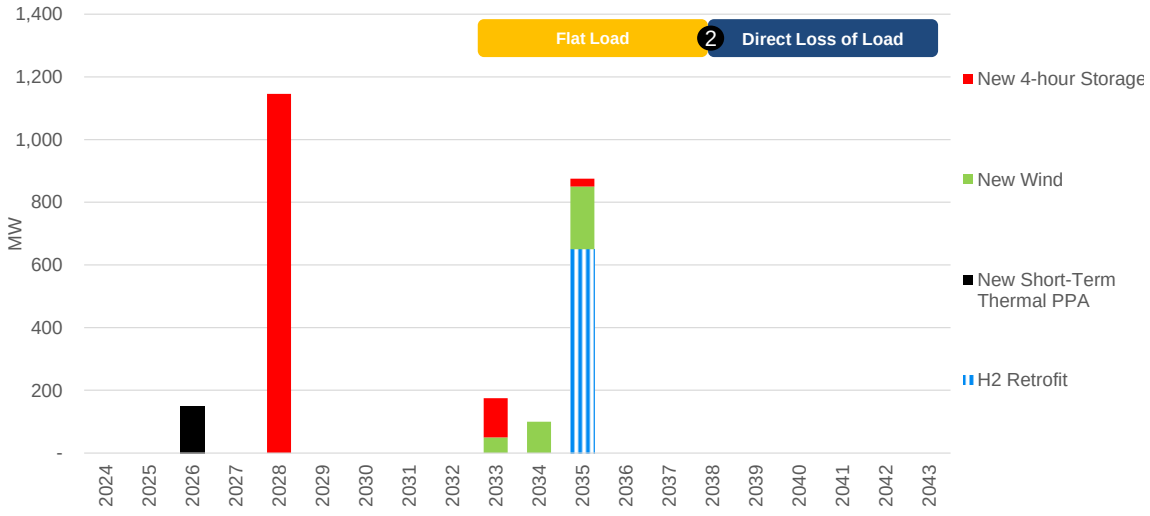
[167] Note that NIPSCO found that the current portfolio's energy position means that additional combined cycle capacity additions would not fit within the energy constraints. Thus, the EPA GHG rules and potential limitations on fossil-fired resources additions without emission controls are irrelevant under the flat load construct. As such, the original six portfolio themes were collapsed into two, varying only the capacity accreditation rules.

[168] Note that for modeling purposes, NIPSCO's existing Sugar Creek combined cycle was assumed to retrofit to enable hydrogen blending in 2035.

9.3.5.2 Flat Load 2 – D-LOL

The Flat Load 2 Portfolio included a total of 150 MW of short-term thermal PPAs and ZRCs, 1,296 MW of new storage capacity (1,146 MW through 2029), and 350 MW of wind over the twenty-year study period. Relative to Flat Load Portfolio 1, Flat Load Portfolio 2 included additional near-term storage to meet near-term capacity accreditation needs under the D-LOL construct and slightly less renewable energy over the long-term. In addition, the portfolio included all EE programs except first tranche of C&I and Residential (2027-2029) and the first two tranches of Behavioral programs (2027-2032). All DR programs were selected except for Water Heaters, EV Charging, and BTM Storage. Figure 9-31Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio D.[169]

Figure 9-31: Flat Load Portfolio 2 – Annual Resource Additions (Nameplate MW)



Note: The 2026 short-term PPA lasts from 2026-2030.

Overall, Figure 9-32Figure 9-12 summarizes the nameplate capacity additions and other resource additions and changes for the flat load portfolios relative to the six other portfolio concepts developed under Reference Case load conditions through 2043.

[169] Note that for modeling purposes, NIPSCO's existing Sugar Creek combined cycle was assumed to retrofit to enable hydrogen blending in 2035.

Figure 9-32: Summary of Incremental Resource Additions across All Portfolios, Including Flat Load Concepts

	Flat Load	Flat Load DLOL	A	B	C	D (all)	E	F
Data Center Load	None	None	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	CCGT<40%	CCGT<40%	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	None	None	Late 2030s	At Start-up	At Start-up
Wind	550	350	1,500	1,850	1,800	1,550	2,250	2,350
Solar	450		2,125	675	3,235	1,275	2,322	1,922
Storage[1]	786	1,296	1,249	1,882	811	959	1,409	2,111
Gas CCGT			2,600	2,600	2,585	3,235		
Gas Peaking	200				400	618		
Gas CCGT w/CCUS							2,340	2,340
Sugar Creek	H2 (or CCUS) Retrofit	H2 (or CCUS) Retrofit	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DSM (DR/EE)[2]	390	440	400	430	230	270	365	365
Total ICAP Additions Through 2043 (excl. DSM/DR)	1,986 MW	1,646 MW	7,474 MW	7,007 MW	8,831 MW	7,637 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer) Covered	~850 MW	~1,350 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

[1] *Includes both 4-hour Lithium-ion and long-duration storage*
[2] *DSM additions calculated as peak capacity contribution in summer of 2043*

9.3.5.3 Flat Load Portfolio Customer Cost Results

Given significantly lower load relative to the Reference Case, the total revenue requirements for the Flat Load portfolios are significantly lower than those developed under the Reference Case load. As shown in Figure 9-33, the 10-year NPVRR is approximately 65% of the NPVRR for the Reference Case portfolios, and the 30-year NPVRR is approximately 50% of the value.

On a levelized cost basis, over the 30-year planning horizon, the costs for the Flat Load portfolio are *higher than* all other Reference Case load portfolios aside from Portfolio F. This suggests that incremental costs associated with larger levels of resource additions in the Reference Case load outlook can be spread over more MWh, such that the per MWh system cost goes down. This is true particularly given NIPSCO's current portfolio composition and the need to bring in new capacity resources like storage even without significant new load growth in the near-term. This is illustrated in Figure 9-34.[170]

[170] Note that this figure just shows portfolios developed under the MISO D-LOL construct. NIPSCO observed similar trends for portfolios developed under current market rules.

Figure 9-33: NPVRR for Flat Load Portfolios

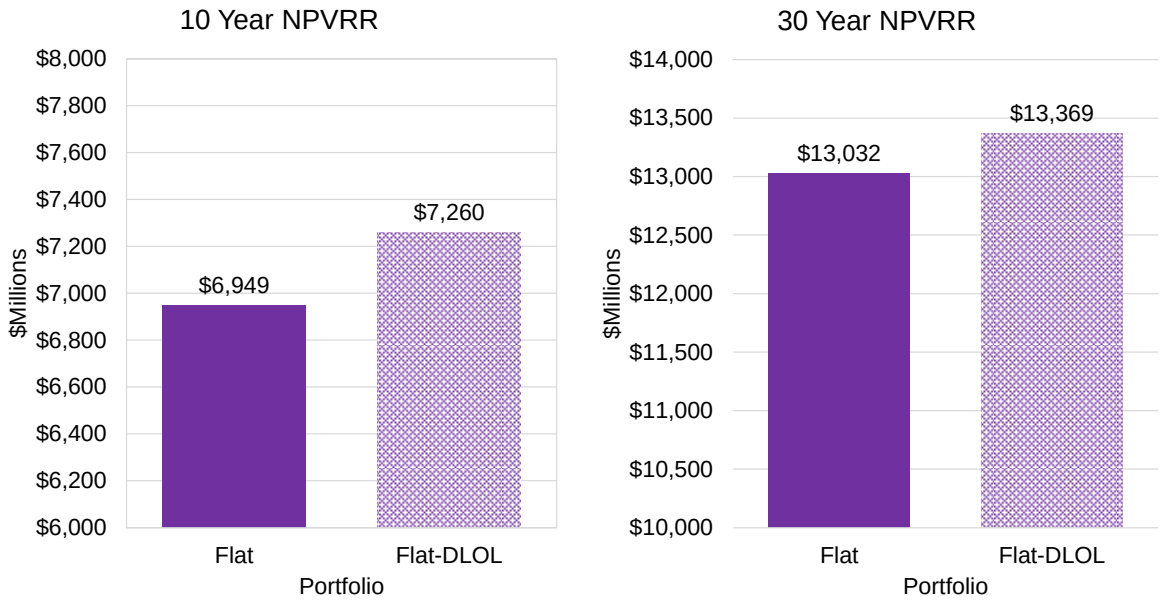
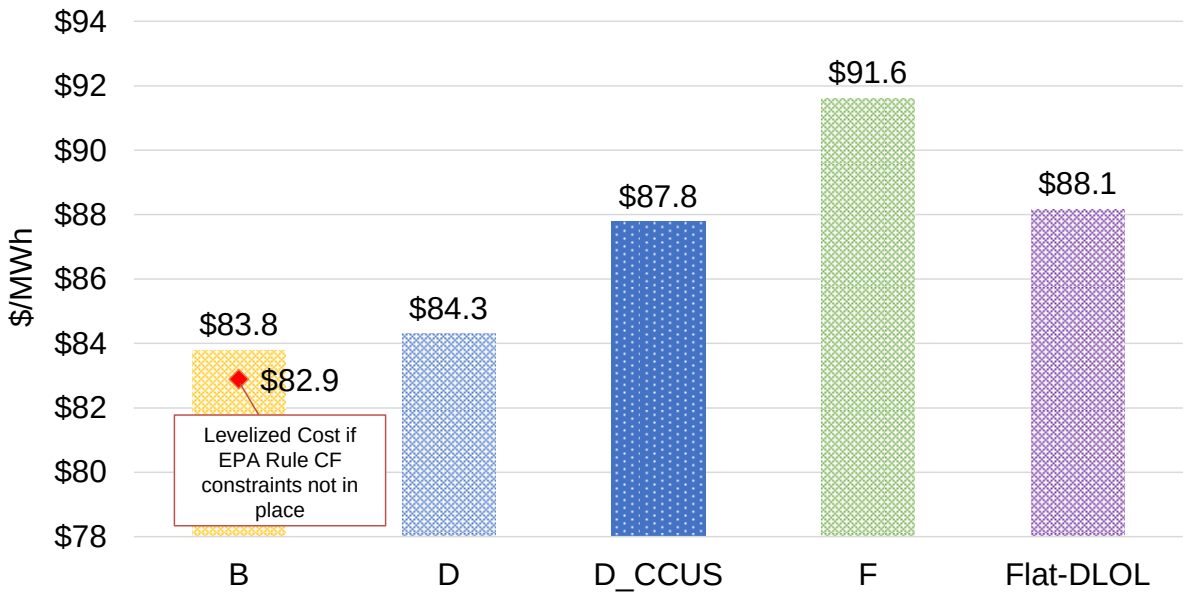


Figure 9-34: Levelized Portfolio Costs for Reference Case and Flat Load Portfolios under D-LOL market Rules



9.3.6 Sensitivity Analysis – Emerging High Load Growth

In addition to the flat load sensitivity, NIPSCO also developed an alternative portfolio construct under an emerging high load sensitivity case, premised on significant new data center load additions to the system based on input from NIPSCO's Economic Development team. As shown in Figure 9-35, relative to the Reference Case, the emerging high load sensitivity incorporates 2,600 MW of additional load by 2028, 4,500 MW by 2030, and 6,000 MW by 2035. As discussed in the next section, a single portfolio was developed under the emerging high load sensitivity under the EPA Rules and D-LOL assumptions (the "Portfolio D" concept).

Figure 9-35: Emerging High Load Sensitivity

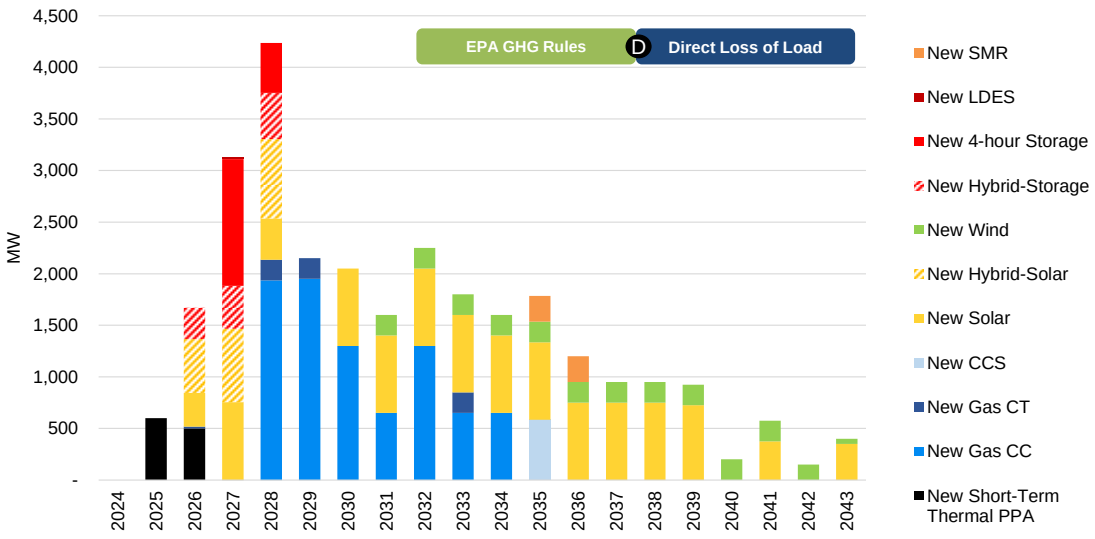
	2028	2030	2035
IRP Peak Load – Flat Load*	~2,300 MW	~2,300 MW	~2,500 MW
+New Load Added for Reference Case	*+600 MW*	*+1,600 MW*	*+2,600 MW*
IRP Peak Load – New Reference Case	**~2,900 MW**	**3,900 MW**	**5,100 MW**
+Emerging Load Sensitivity	*+2,600 MW*	*+4,500 MW*	*+6,000 MW*
Total IRP Peak Load With Emerging Load Sensitivity	**5,500 MW**	**8,400 MW**	**11,100 MW**

Incremental to Reference Case

9.3.6.1 Emerging High Load Portfolio – EPA GHG Rules and D-LOL

The Emerging High Load Portfolio included a total of 1,100 MW of short-term thermal PPAs and ZRCs, 8,435 MW of combined cycle capacity (3,885 MW through 2029), 620 MW of natural gas peaking capacity (420 MW through 2029), 2,886 MW of new storage capacity (all through 2029), 2,400 MW of wind, 11,694 MW of solar (3,494 MW through 2029), 585 MW of combined cycle capacity with CCUS, and 500 MW of SMR nuclear capacity over the twenty-year study period. In addition, the portfolio included all EE programs except for the final tranches of C&I, Residential High, and Residential Low-Medium (2033-2046). All DR programs were selected except for Dynamic Rates. Figure 9-36 provides a summary of the annual nameplate capacity resource additions for the Emerging High Load Portfolio.

Figure 9-36: Emerging High Load Portfolio – Annual Resource Additions (Nameplate MW)



Note: The short-term PPAs have various durations through 2030.

Overall, the emerging high load analysis highlighted that NIPSCO would require significant capacity additions from a diverse set of new resource types to meet both future capacity and energy requirements, particularly over the next ten years. Major observations and findings from the sensitivity analysis included:

- Significant near-term load growth would require large capacity additions through 2029, including:
  - Over 1,000 MW of Thermal PPAs and ZRCs
  - Nearly 3,500 MW of solar and nearly 3,000 MW of storage
  - Over 4,000 MW of natural gas capacity
- New combined cycle capacity is needed for near-term energy requirements, although the portfolio could be short energy for periods of time depending on the pace of new CCGT additions. Importantly, flexibility to operate CCGTs above 40% prior to the implementation of the GHG Rules in 2032 could allow for most energy needs to be met, but EPA Rules on capacity factor constraints thereafter could result in higher levels of energy market purchases.
- A diverse mix of long-term resource additions would be required, contingent upon resource availability constraints and technological advancement. These long-term resource additions would include:
  - Additional CCGT and gas peaking capacity;

- Significant amounts of post-2030 solar (8,200 MW) and wind (2,400 MW);
- CCUS and SMR capacity as it becomes available, showcasing the potential for clean form resource additions to provide potentially carbon-free capacity that could run at high capacity factors.

- Significant energy efficiency and demand response additions would be expected to support portfolio requirements.

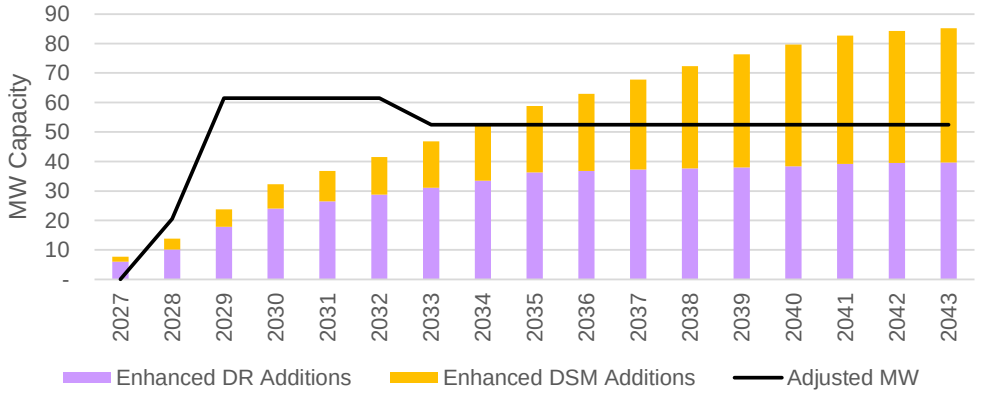
9.3.1 Sensitivity Analysis – Additional DSM

NIPSCO also performed a sensitivity analysis to evaluate the impact of moving from the RAP DSM levels to the Enhanced RAP and MAP savings trajectories for energy efficiency and demand response programs, respectively. As documented in Section 5, moving from RAP to Enhanced RAP and MAP results in larger savings, but also higher program costs.

NIPSCO evaluated the impact of moving to the MAP DR bundles and the Enhanced RAP EE bundles under Portfolio D. This was done by effectively "forcing in" the same DR and EE bundles as identified in the portfolio optimization analysis, but at the MAP or Enhanced RAP level instead of at the RAP level. This has the impact of both reducing energy requirements and mitigating the need for some capacity additions. NIPSCO identified approximately 85 MW of additional peak load reduction potential over time. This additional DSM was able to displace 75 MW of incremental natural gas peaking capacity additions, as summarized in Figure 9-37.

The impact of reduced energy requirements was evaluated through a re-dispatch of the portfolios in the Aurora portfolio model, while 75 MW of future natural gas peaking capacity additions around 2030 were removed to reflect the reduced capacity obligation.

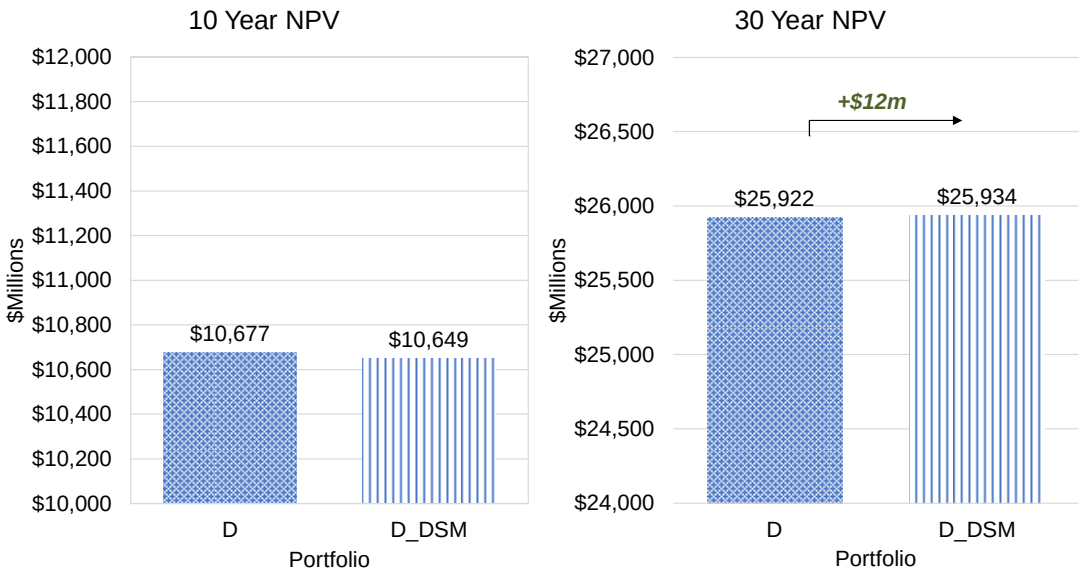
Figure 9-37: Additional DSM versus Avoided Peaking Capacity Additions



Under Reference Case conditions, NIPSCO's analysis found that moving from the RAP to the Enhanced RAP and MAP DSM bundles would increase the 30-year NPVRR by $12 million for Portfolio D, but result in a lower NPVRR on a ten-year basis. As illustrated in Figure 9-38, over the first ten years, the total revenue requirement for the D_DSM portfolio is lower than Portfolio D due to avoided capital and O&M costs from reduced natural gas peaking capacity

additions. However, over 30 years, the D_DSM portfolio costs are higher than Portfolio D's, as higher DSM program costs outweigh capital cost savings.

Figure 9-38: NPV Impact of Shifting from RAP to Enhanced RAP or MAP – Portfolio D Example



9.3.2 Scorecard Summary

Figure 9-39 presents a summary of all scorecard metrics for each of the eight portfolios that were evaluated under Reference Case load conditions. This includes the cost metrics associated with the Reference Case NPVRR, the risk metrics associated with the major outcomes from the scenario and stochastic analyses, carbon emissions, reliability metrics, and impacts on the local economy, as described above. The following key observations were made:

- Customer costs in the Reference Case generally increase as additional constraints are placed on the portfolios, including D-LOL accreditation rules, EPA GHG rules, and limits on new fossil additions without emission controls.

- Across the five market scenarios, the Portfolio D variants and Portfolios E and F have the lowest range of cost outcomes. The Portfolio D variants provide optionality for the portfolio in the face of uncertainty associated with future environmental policy.

- Across the stochastic cost distribution, portfolios with more natural gas-fired capacity (Portfolios A through D) exhibit higher cost risk than those with less natural gas capacity (Portfolios E and F). This results in a wider range of cost outcomes, with higher 95th percentile cost risk and lower 5th percentile cost opportunity.

- Portfolios that include more natural gas capacity and do not retrofit that capacity to control for carbon emissions result in higher overall emissions intensity over the 2024-2040 period. The Portfolio D variants reduce emission intensity over time, and Portfolios E and F have the lowest overall.

- Portfolio D performs best on the reliability and flexibility metrics, given larger amounts of flexible, long-duration dispatchable capacity. Portfolios E and F are most exposed to forced market risk exposure, given higher levels of intermittent capacity and lower amounts of long-duration dispatchable capacity.

- Portfolios E and F have the highest investment in the local economy due to higher-cost resource additions. The Portfolio D variants follow, as a result of investment in emission control retrofits in the mid-to-late 2030s, while Portfolios A through D have slightly less local investment overall.

Figure 9-39: Portfolio Scorecard

	A	B	C	D	D-CCUS	D-H2	E	F
Carbon Emissions Constraint	No EPA GHG Constraints		EPA GHG Rules				Emissions Controls At Start-Up	
MISO Market Rules	Current Market Rules	Direct Loss of Load	Current Market Rules	Direct Loss of Load			Current Market Rules	Direct Loss of Load
Cost To Customer 10-year NPVRR (Ref Case) $M	$10,307 +$62	$10,735 +$491	$10,244 -	$10,677 +$433	$10,993 +$749	$10,993 +$749	$10,951 +$705	$11,309 +$1,065
Cost To Customer 30-year NPVRR (Ref Case) $M	$25,142 -	$25,626 +$484	$25,471 +$329	$25,922 +$780	$27,236 +$2,094	$27,999 +$2,857	$27,984 +$2,842	$28,756 +$3,614
Cost Certainty 30-year Scenario Range NPVRR $M	$9,669 +$4,952	$10,245 +$5,529	$7,815 $3,098	$9,286 $4,569	$5,414 $697	$4,717 -	$5,232 $516	$5,451 +$735
Cost Risk 95th % Cost Risk	$53.1 +$8.1	$53.3 +$8.4	$54.2 +$9.2	$56.8 +$11.9	$54.1 +9.2	$54.1 +9.2	$45.1 +$0.2	$45.0 -
Lower Cost Opp. 5th % Cost Risk	-$37.4 +$1.8	-$37.3 +$1.9	-$37.4 +$1.8	-$39.2 -	-$38.9 +$0.3	-$38.9 +$0.3	-$35.4 +$3.8	-$36.3 +$2.9
Carbon Emissions M of tons/MWh 2024-40 Cum.	0.23 +0.14	0.24 +0.15	0.19 +0.10	0.22 +0.13	0.18 +0.09	0.20 +0.11	0.09 -	0.09 -
Reliability Forced Market Exposure (GWh)	235 +231	86 +82	89 +85	4 -	4 -	4 -	793 +789	515 +511
Flexibility New capacity able to respond within 30 mins (MW)	3,849 -963	4,482 -330	4,121 -691	4,812 -	4,632 -180	4,812 -	3,905 -907	4,456 -356
Local Economy NPV of property taxes	$1,849 -$849	$1,853 -$845	$1,938 -$760	$1,840 -$858	$2,229 -$484	$2,097 -$609	$2,619 -$79	$2,698 -

Note that carbon emissions for Portfolios A and B are summarized from the analysis performed with Portfolios A and B not complying with EPA GHG rules even though scenario analysis was performed with the prevailing scenario environmental policy drivers in place.

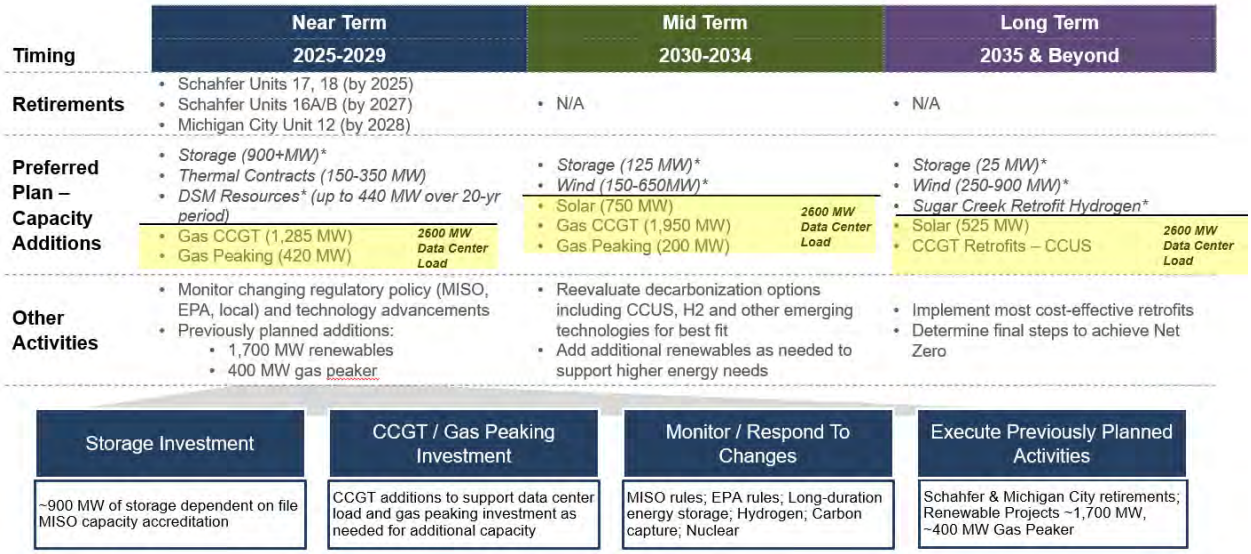
9.4 Preferred Portfolio

NIPSCO has identified Portfolio D_CCUS as its preferred portfolio based on the following key considerations:

- Given the need for dispatchable capacity in MISO and FERC's approval of the D-LOL market reforms on October 25, 2024, NIPSCO should plan for compliance, focusing on Portfolios B, D, and F.
- Portfolio B does not prepare to comply with EPA rule constraints, as it would likely need additional peaking capacity or additional solar + storage to make up for the capacity factor limitations on new combined cycles, which are accounted for in the Portfolio D variants.
- The Portfolio D variants all have the same resource mix through 2030, but Portfolio D (without CCUS or Hydrogen retrofits) does not reduce emissions over time. Given that future hydrogen supply is more uncertain than future CCUS deployment, NIPSCO is left with Portfolio D_CCUS or Portfolio F as options to meet its long-term emissions reduction goals.
- Overall, Portfolio D_CCUS provides more optionality for NIPSCO around future decarbonization actions and performs well relative to Portfolio F:
    - Portfolio D_CCUS has lower customer cost due to lower storage needs through 2030 and due to delaying decarbonization retrofits until they are more feasible in the 2030s.
    - Portfolio D_CCUS has comparable and slightly better cost certainty compared to Portfolio F, particularly associated with optionality around future decarbonization actions in the face of external market uncertainty.
    - Portfolio D_CCUS has marginally higher annual cost risk than Portfolio F due to higher commodity price risk.
    - Portfolio D_CCUS has higher emission intensity than Portfolio F due to additional natural gas generation, but still decarbonizes by end of 2030s.
    - Portfolio D_CCUS has significantly higher reliability due to more long-duration dispatchable capacity, including from natural gas resources. Portfolio D_CCUS also has better resource flexibility due to more dispatchable natural gas-fired capacity.
    - Portfolio D_CCUS has lower local economy benefits than Portfolio F due to lower capital spend.

Figure 9-40 summarizes the elements of NIPSCO's preferred plan, including the expected ranges of capacity additions by resource type through the 2029 period. As additional diligence is performed and as more information is obtained regarding market, policy, and technology change, NIPSCO will refine the specific capacity addition numbers.

Figure 9-40: Preferred Portfolio Capacity Additions



**Italicized resources listed above would be needed under all portfolios (including those without data center load).*

Regardless of future data center growth, this preferred portfolio includes near-term thermal contracts to firm up NIPSCO's capacity position as a result of D-LOL market reforms and over 900 MW of storage capacity through the end of the decade. If data center load materializes in line with the Reference Case load forecast, NIPSCO's preferred portfolio would also include up to 1,300 MW of combined cycle capacity and around 420 MW of natural gas peaking capacity. Over the 2030-2034 time period, the preferred portfolio includes additional storage and wind, with additional solar, combined cycle, and peaking capacity depending on the magnitude of NIPSCO's load growth. Over the long-term (2035 and beyond), the preferred portfolio includes additional storage, wind, and solar capacity, along with retrofits of combined cycle capacity (existing and new) to reduce CO2 emissions via CCUS or hydrogen.

Figure 9-41, Figure 9-42, Figure 9-43, and Figure 9-44[171] show NIPSCO's projected supply-demand balance under the preferred portfolio for the summer, winter, fall, and spring

[171] Note that the figures display the DSM selection for Portfolio D, as documented in Figure 9-10 and Figure 9-11. However, NIPSCO plans to pursue a DSM plan consistent with the incremental DSM selections identified in the Flat Load sensitivity, as documented in Section 9.3.5.2 and shown in the Preferred Portfolio summary in Figure 9-40, This would result in slightly more DSM than summarized in the supply-demand figures.

seasons, respectively.[172] As shown, natural gas and storage resources contribute most to the growing supply need across all seasons, particularly as the D-LOL construct reduces the expected accreditation of solar and wind capacity in 2028 and beyond.

Figure 9-41: Preferred Portfolio Supply-Demand Balance - Summer

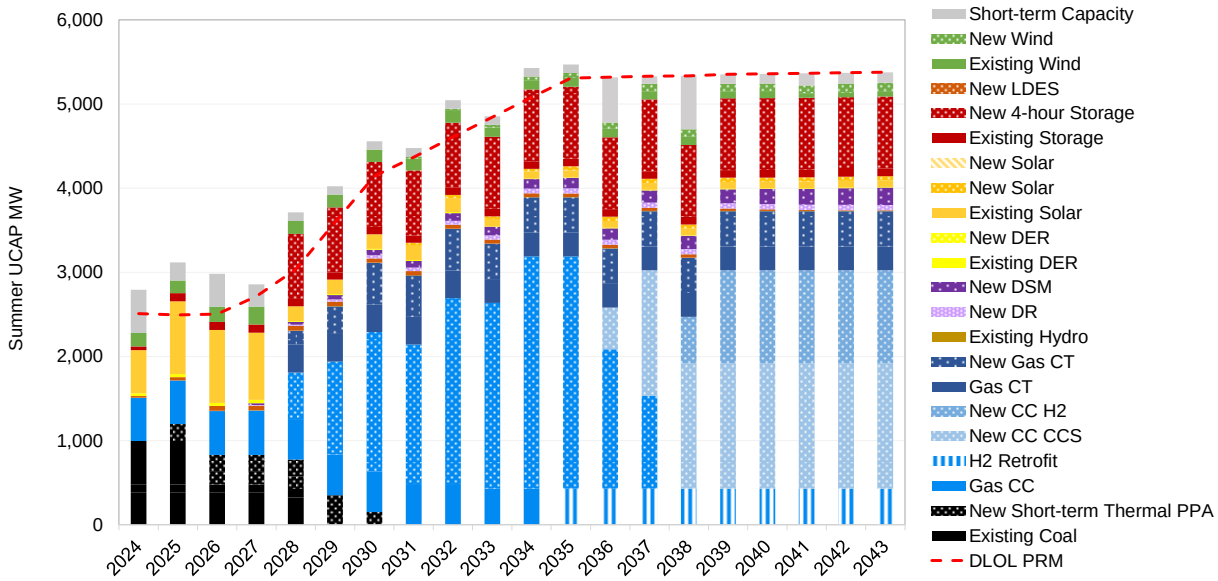
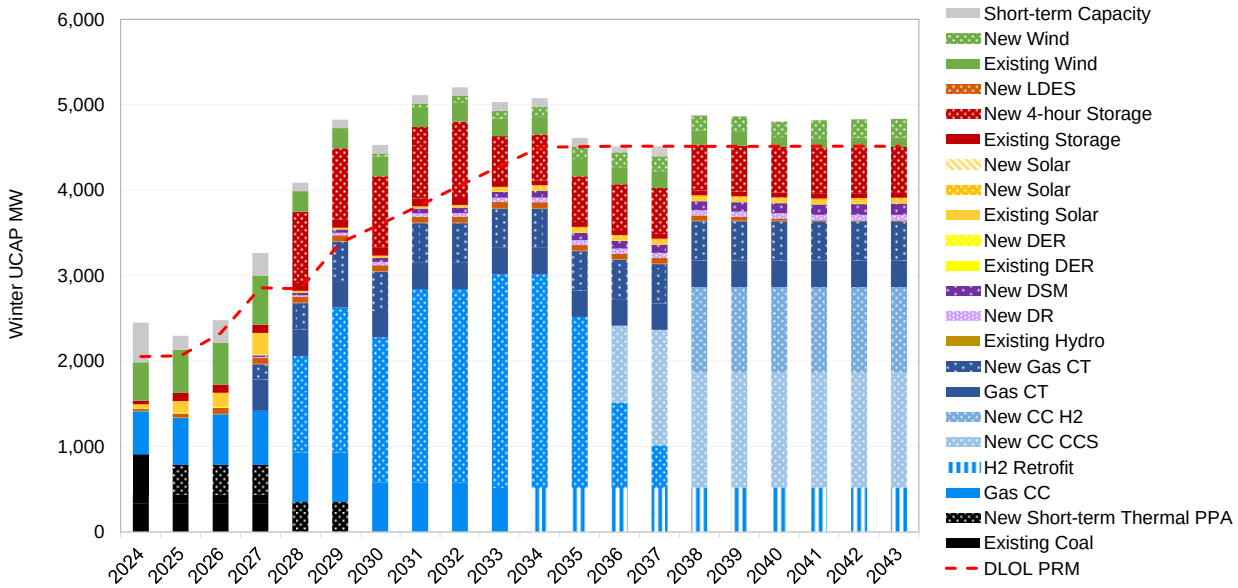


Figure 9-42: Preferred Portfolio Supply-Demand Balance - Winter



[172] Note that through the mid-to-late 2030s, the supply-demand balance reflects potential outage periods as combined cycle resources convert to CCUS or retrofit with hydrogen blending capabilities. Market purchases were assumed to cover short-term capacity needs in line with potential plant outages.

Figure 9-43: Preferred Portfolio Supply-Demand Balance - Fall

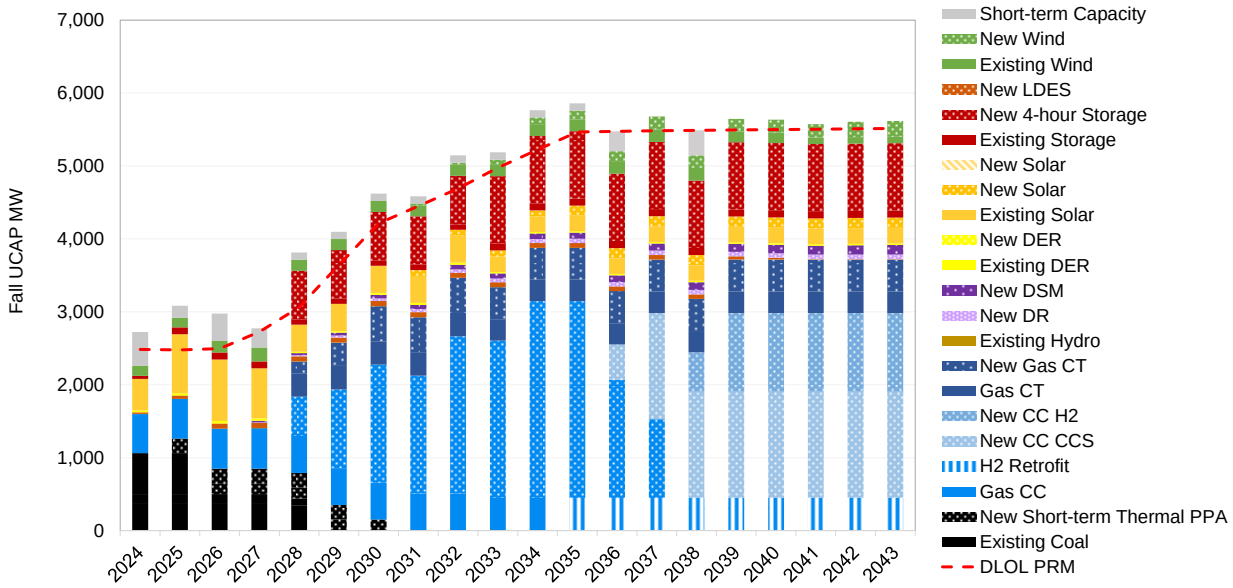


Figure 9-44: Preferred Portfolio Supply-Demand Balance - Spring

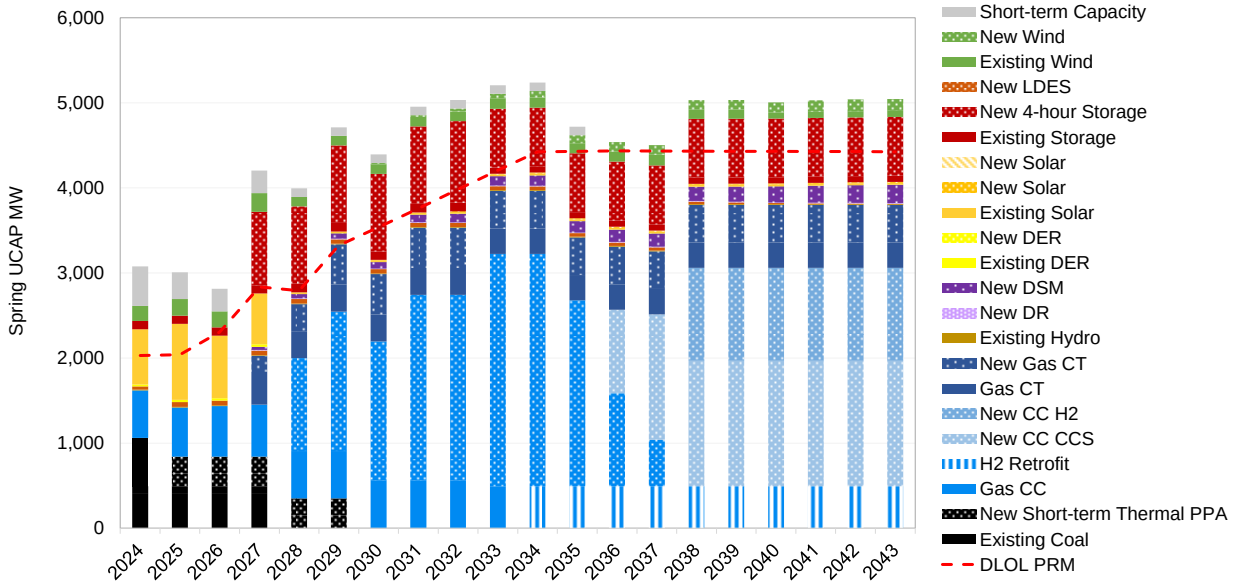
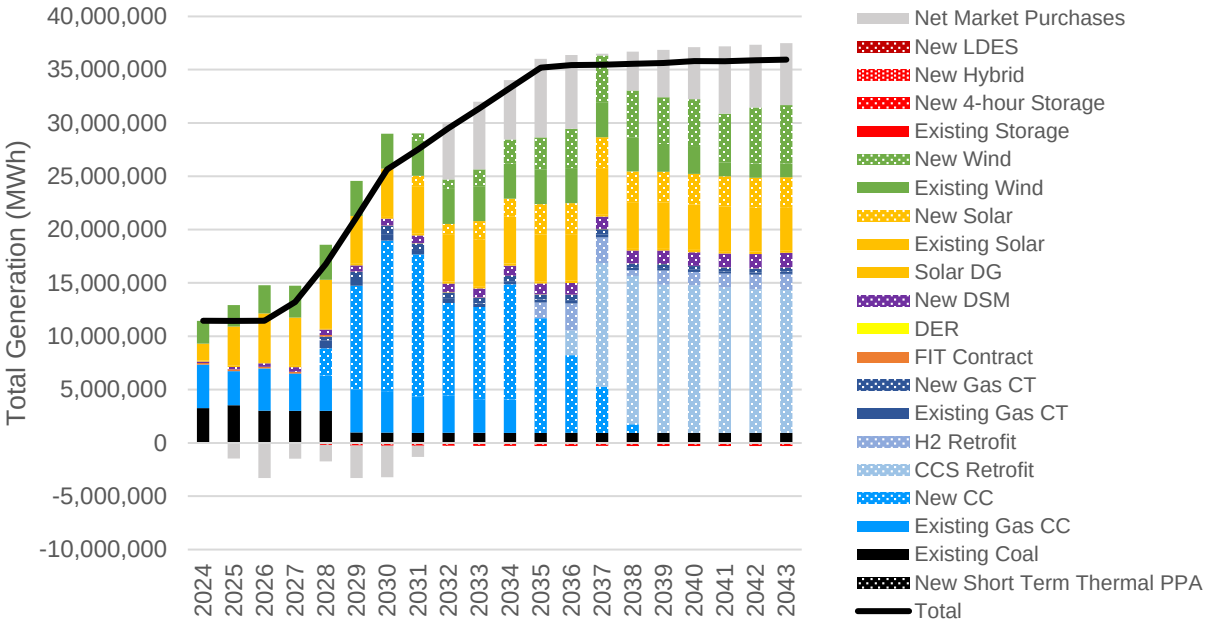


Figure 9-45 summarizes the expected energy balance for the preferred portfolio over time. As shown, new energy from combined cycle capacity additions is projected to meet growing load into the early 2030s. Under Reference Case conditions, the enforcement of a 40% capacity factor limit on new combined cycles as a result of the EPA GHG rules would result in a decline in natural gas generation after 2031. Over the mid-to-long term, NIPSCO's preferred portfolio adds new wind and solar energy and realizes increased energy savings from DSM programs.[173] In addition, in the mid-2030s, combined cycles are expected to covert to CCUS or blend hydrogen, with the largest energy contribution expected to come from CCUS facilities, given high projected capacity factors as a result of federal tax credit incentives.

Figure 9-45: Preferred Portfolio Energy Mix



9.4.1 Preferred Portfolio Summary

NIPSCO's preferred portfolio was developed to ensure that a reliable, compliant, flexible, diverse and affordable set of resources is available to meet future customer needs. As part of the portfolio selection process, NIPSCO also considered the impacts to its employees, the environment, reliability, and impacts on the local economy. NIPSCO's resource strategy is expected to:

- Continue to implement the Company's portfolio transition by integrating new renewable projects currently under development and taking the necessary steps to retire Units 17 and 18 at the Schahfer coal plant by the end of 2025 and Unit 12 at the Michigan City coal plant by the end of 2028;

[173] For modeling purposes, newly selected DSM programs are evaluated on the "supply side" and are shown accordingly.

- Continue the Company's commitment to EE and DR by executing the current filed DSM plan and continuing to plan for the most expansive economic residential and commercial DSM programs identified in NIPSCO's portfolio optimization analysis, as well as potential emerging energy savings and demand response opportunities with new large loads;

- Integrate new resources to meet the energy and capacity needs of potential large new customers;

- Ensure that system reliability is preserved as NIPSCO and the broader MISO market increase the amount of intermittent resource capacity and operate within the new D-LOL construct;

- Provide a cost-effective portfolio for customers while also balancing other objectives associated with rate stability, environmental sustainability, and positive social and economic impacts;

- Preserve flexibility in resource procurement and future resource optionality, particularly associated with long-term decarbonization initiatives;

- Continue to actively monitor federal policy, technology, and MISO market trends, while staying engaged with project developers and asset owners to understand the landscape of new resource options;

- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services;

- Continue to comply with NERC, MISO, and EPA standards and regulations.

It is important to remember that this preferred portfolio as part of the 2024 IRP is a snapshot in time and while it establishes a direction for NIPSCO, it is subject to change as the external operating environment changes. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

9.4.2 Financial Impact

Figure **9-46** shows NIPSCO's financial impact of Portfolio D_CCUS over the planning period. While NIPSCO's preferred portfolio intentionally retains flexibility, this summary is being provided as a baseline benchmark.

The 30-year NPVRR is broken down into operating and capital costs. The operating costs are split into the fixed and variable costs associated with both existing units and future resources, as well as contract costs and net market purchases. The capital costs include all capital-related costs for existing units and costs related to the acquisition of new resources in the preferred

portfolio. These costs include depreciation expenses, capital charges, and taxes.[174] In order to present a levelized net present value rate summary, the total energy forecast for NIPSCO is also discounted over the 30-year period at the same rate.

Figure 9-46: Financial Impact Summary[175]

Financial Impact Summary	
Operating Costs ($000)	$14,256,270
Capital Costs ($000)	$12,979,627
Total Revenue Requirement ($000)	$27,235,897
Total Energy Requirement (GWh)	310,807
Cents/kWh	8.76

Note that Total Energy Requirement is the discounted value of 30 years of energy forecasts, rather than a total sum. This is done to allow for the cents per kWh summary to be reflective of a levelized net present value calculation.

NIPSCO expects that existing cash balances, cash generated from operating activities, and funding through inter-company loan arrangements with its parent company will meet anticipated operating expenses and capital expenditures associated with NIPSCO's short-term action plan.

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from a number of sources including: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; (v) new equity capital and (vi) tax equity financing. NiSource, Inc. procures external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB at Fitch and Baa2 at Moody's.

9.4.3 Developments That Will Shape NIPSCO's Preferred Portfolio Implementation

As summarized in Section 2, NIPSCO identified several key themes that have influenced the development of this 2024 IRP and that will shape the ultimate implementation of NIPSCO's short-term action plan. As noted above, NIPSCO's preferred portfolio incorporates ranges of new resource additions to reflect the fact that several evolving external factors will influence final procurement decisions and future portfolio actions. These can broadly be categorized into factors associated with new large load additions; the implementation of MISO market rules changes;

[174] Note that the value of federal tax credits are rolled into the net taxes line item.

[175] The information is based on Portfolio D_CCUS under the Reference Case market assumptions. As discussed throughout this section, to preserve flexibility, NIPSCO's ultimate preferred portfolio may incorporate other long-term strategies around the D Portfolio concepts.

federal environmental policy, particularly associated with the future implementation of EPA GHG rules; and technology change.

9.4.3.1 Large Load Growth

NIPSCO's Reference Case load forecast incorporates 2,600 MW of new large load growth by 2035. Such load growth will require significant new resource additions to serve both energy and capacity requirements. The magnitude and pace of NIPSCO's load growth, however, is not certain, and NIPSCO will need to refine its resource acquisition strategy as specific customer requirements are defined. Within the 2024 IRP, NIPSCO evaluated a Flat Load portfolio and an Emerging High Load sensitivity with up to 8,600 MW of new load by 2035. These analyses provide a framework within which NIPSCO can implement its short-term action plan.

9.4.3.2 MISO Market Rules Changes

FERC approved MISO's D-LOL filing on October 25, 2024, so NIPSCO must now be prepared to operate under a revised capacity accreditation methodology. The portfolios developed in this 2024 IRP were evaluated based on the best accreditation information available as of the report's submission date, but NIPSCO expects MISO to continue to refine its modeling methodologies and provide additional guidance on future capacity accreditation levels between now and the 2028/29 planning period. Regional changes in load growth, load shapes, and the penetration of wind, solar, and storage resources will all impact future accreditation values for NIPSCO's resources (both existing and new), and NIPSCO will need to track updates accordingly. This 2024 IRP has concluded that new storage resources will likely play a role as the near-term "swing" resource type, meaning that NIPSCO will need to be flexible in its resource acquisition strategy to adapt its procurement activities to an evolving capacity need.

9.4.3.3 Federal Environmental Policy

Federal environmental policy is likely to remain dynamic. Most notably, the EPA GHG rules face both political and legal uncertainty that NIPSCO will continue to track, and these rules will dictate how NIPSCO can operate new natural gas-fired additions. While the Company's preferred portfolio was evaluated with the rules in force, NIPSCO's preferred portfolio is flexible enough to operate effectively even if challenges to the rules are successful or if they are revised in the future. In addition, the long-term decarbonization initiatives embedded in NIPSCO's preferred portfolio are contingent on the availability of federal tax credits for renewable, storage, and CCUS projects. NIPSCO will continue to monitor federal policy as it positions long-term portfolio actions and evaluates the timing of certain resource additions or retrofits.

9.4.3.4 Technology Change

The implementation of NIPSCO's preferred portfolio over the long-term is highly dependent on the evolution of emerging power sector technologies. Most notably, NIPSCO expects to continue to study CCUS and hydrogen in more detail over the next several months and years to understand the costs, challenges, and opportunities associated with such technologies. In addition, NIPSCO expects to further diligence its options associated with LDES technology,

particularly since several portfolios identified LDES as a potential near-to-mid-term resource that provides strong capacity accreditation and hedges against load and intermittent resource output uncertainty. Finally, NIPSCO will continue to assess other emerging technologies that may play a role in its future portfolio, including nuclear.

9.4.3.5 Other Factors

NIPSCO will again continue to perform project-specific analyses for any new loads and resources that may enter the portfolio to evaluate items such as congestion and nodal price risk, energy deliverability, and other reliability topics. This may include detailed nodal and power flow modeling and other local transmission and distribution system analyses.

9.5 Short-Term Action Plan

NIPSCO's short-term action plan covers the period 2025 to 2029 and includes several elements, as summarized in Figure 9-47.

9.6 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost-effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This 2024 IRP incorporated several emerging trends and expanded the analysis of risk and reliability to identify a preferred portfolio that is highly flexible to changing external conditions. It is no longer possible to view the world in terms of choosing a simple least cost option, and NIPSCO has identified an implementation roadmap that reflects the need to manage customer costs, minimize future environmental impacts, ensure reliability, maximize resource diversification, and preserve optionality over the long-term.

Figure 9-47: Short-Term Action Plan Summary

Complete and place in service the remaining renewable facilities and gas peaker project approved by the IURC but not yet operational
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by the end of 2025
Complete the retirement of Michigan City 12 by the end of 2028.
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Continue implementation of filed DSM Plan for 2025 through 2026
Select the best storage projects from the 2024 RFP, optimizing existing interconnection rights and federal tax credit opportunities
Procure short-term capacity as needed from the 2024 RFP, the MISO market, or through short-term bilateral capacity transactions
Continue discussions with new data center customers and refine the near-to-mid-term load outlook as contracts are signed and expected loads are firmed
Perform additional diligence on the costs, feasible locations, and operational characteristics of new natural gas combined cycle and peaking additions necessary to meet new data center load.
Study potential future decarbonization pathways for gas-fired generation further, particularly CCUS and hydrogen blending
As needed, conduct a subsequent RFP(s) to identify additional resources that may be available with attributes that are consistent with those required to implement the preferred portfolio
Explore potential pilot projects from the RFP associated with emerging technologies, such as long duration energy storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
Perform additional reliability analysis within the NIPSCO system as needed to ensure evolving portfolio meets all reliability needs and requirements
Comply with NERC, EPA, and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

Section 10. Customer Engagement

10.1 Enhancing Customer Engagement

Understanding and incorporating the diverse needs and perspectives of NIPSCO's customers is important, and the Company is focused on continuously improving how it serves and engages with its customers. Whether it is transitioning to lower-cost and cleaner energy sources, helping customers understand changes and enhancements to their service, or listening to customer feedback about how they want to interact with NIPSCO, customers have been and continue to be the central focus.

NIPSCO was named among the most trusted utility brands by Escalent, following its 2024 Cogent Syndicated Utility Trusted Brand & Customer Engagement: Residential study. The ranking recognized only 33 brands nationwide, with NIPSCO scoring in the top three of their Midwest Region combination gas/electric peers. Escalent measured factors including customer advocacy, safety and reliability and environmental focus, among others. Their findings were based on a survey of more than 61,000 residential electric and natural gas customers, which included 142 electric, natural gas and combination utilities.

That trust is built through a variety of ways including our work to continually enhance our customer engagement, ensuring the services we provide are bringing customers value.

10.1.1 Leveraging Customer and Stakeholder Feedback

NIPSCO relies on customer feedback to uncover service improvement opportunities. Those feedback mechanisms include the Customer Advisory Panel, J.D. Power customer satisfaction surveys, MSR Group surveys, online customer panels, and comments and complaints that are emailed or called in to NIPSCO's customer care center, as well as the IURC Consumer Affairs Division. NIPSCO also surveys customers to determine customer satisfaction with its customer care center, interactions with field personnel, and with other interactions, such as mobile, integrated voice responses and the website. The company also researches best practices demonstrated by those within the utility sector and those outside the industry. Customer feedback is the primary driver behind many of the changes to operations, improvements to customer communications, enhancements to services and added programs, and other offerings that have been instituted in recent years.

Direct customer feedback has been critical in helping NIPSCO and its parent company, NiSource, to better understand and prioritize customer needs. Based on customer feedback and engagement data from February 2022 through June 2024, NIPSCO has significantly enhanced its customer service capabilities through various digital initiatives:

1. **Chatbot and Live Chat**: The chatbot has handled a substantial number of conversations, facilitating transactions such as account balance inquiries, payment status checks, and bill retrieval. Live chat availability has been expanded to improve accessibility, demonstrating NIPSCO's commitment to responsive customer support.

2. **Mobile App Enhancements**: NIPSCO has made 34 enhancements to its mobile app, including intuitive shortcut tiles for functions like payments, account registration, and service requests. The addition of three new payment plan options via the app has empowered customers to manage their finances conveniently.

3. **Website Improvements**: Over 90 enhancements on the NIPSCO website have enhanced user experience, featuring an interactive bill tool, a streamlined navigation menu, and improved accessibility for users with disabilities. Real-time email validation ensures accurate communications, while enhanced payment management capabilities cater to diverse customer needs.

4. **Digital Self-Service Adoption**: The adoption rate of digital self-service options has increased, with 82.7% of transactions completed through web, mobile app, IVR, and chatbot channels by June 2024. This growth highlights the effectiveness of NIPSCO's digital strategy in empowering customers to manage their accounts independently.

5. **Mobile App Usage**: The NIPSCO mobile app has been downloaded over 218,000 times since 2022, supporting more than 74,000 transactions related to service requests such as starting, stopping, or moving services.

Notably, NIPSCO.com was ranked the #1 Utility Website by E Source in 2023. NIPSCO participated in a Website Benchmark assessment through E Source, a company with 30+ years of industry expertise. The biennial list assesses utility websites in the US and Canada for findability, functionality, content and appearance. The report cited that utility websites must offer digital tools that support customers equitably, regardless of their background, abilities, language or level of access to technology. By doing so, utility companies promote self-service offerings that increase customer satisfaction and reduce operating costs, among other benefits.

These initiatives collectively underscore NIPSCO's efforts to enhance customer convenience, improve service accessibility and empower customers through efficient digital solutions. Customer feedback also allows NIPSCO to drive continuous incremental improvements across existing initiatives, including paperless enrollments and ongoing website enhancements and helps NIPSCO better understand areas in which customers are satisfied with their interactions and areas in which we can continue to improve across technologies, processes and experiences.

It is important for customers to understand what they are paying for and that they are getting good value. Along with working to improve these direct customer channels, NIPSCO has also made service improvements in recent years that directly benefit customers, including:

- Modernizing the electric system to improve system reliability, reduce outage time, and harden it against severe weather

- Replacing over 300 miles of a specific vintage of underground cable that was causing up to 90% of the outages on its underground system

- Modernizing electric distribution and transmission substations with equipment that helps monitor asset and system health, ensuring these technologies achieve their maximum life
- Inspecting and treating over 300,000 wood poles helping to harden its distribution system and improve reliability
- Maintaining reliability by coating and extending the life of more than 3,227 steel transmission structures since 2016 to protect against physical damage and weather conditions
- Continuing investments to thwart and protect against cybersecurity threats
- Reducing power outage durations by 40%
- Providing customers with 100% of the revenues when NIPSCO sells the excess power it generates back to the grid – including sales from the newly added renewable energy
- $70 million in savings for customers through eliminating fuel, purchase power, and operating and maintenance costs by retiring NIPSCO's coal-fired generating units

10.1.2 Customer Education – Generation Transition, Energy Efficiency and Assistance

NIPSCO's 2024 Integrated Resource Plan continues to demonstrate that a more balanced electric generation portfolio is the best option for customers in terms of long-term affordability and reliability in terms of long-term affordability and reliability. As NIPSCO continues this generation transition, it is important for customers to understand why and how this transition will occur to maintain customer trust and confidence in the essential, reliable energy this balanced portfolio provides.

Along with making this cost-effective electric generation transition, NIPSCO remains committed to supporting its customers through a variety of assistance programs. For those facing financial difficulties, NIPSCO offers comprehensive bill payment assistance initiatives. These include payment agreements tailored to provide flexibility during times of financial strain, such as three-month, six-month, and twelve-month options designed to ease the burden of overdue balances. Introduced in 2020, these plans continue to be available to eligible customers, ensuring manageable payment schedules that align with their financial circumstances.

In addition to its in-house payment plans, NIPSCO collaborates with federal, state, and local agencies to extend support through programs like LIHEAP. LIHEAP provides vital financial aid to households with incomes at or below 60% of the State Median Income, helping them manage

their energy bills during critical times. Applications for heating assistance under EAP are accepted annually from Oct. 1 through April 14 ensuring timely support for eligible families across Indiana.

Furthermore, NIPSCO's CARE Program offers additional discounts on energy bills for qualifying customers using natural gas for heating, supplementing the benefits provided by LIHEAP. This program runs during the colder months of the year when bills can be at their steepest, providing significant savings depending on household income levels. For customers facing specific financial hardships related to energy costs, NIPSCO's Hardship Program offers targeted assistance through local Community Action Agencies, providing much-needed relief for natural gas customers falling between 151-250% of the Federal Poverty Level.

Since NIPSCO's last Integrated Resource Plan in 2021, two additional hardship programs have been introduced to assist NIPSCO customers:

- **SERV:** The Supply Energy Resources to Veterans (SERV) program is an income-eligible assistance program that offers a one-time benefit to our active military and eligible veteran customers that fall between 0-250 percent of the federal poverty level and is in need of financial assistance with gas residential utility charges. Learn more at https://www.nipsco.com/bills-and-payments/financial-support/income-eligible-assistance-programs

- **SILVER:** The Seniors in Indiana Low-income & Vulnerable Energy Resource (SILVER) program is an income-eligible assistance program that offers a one-time benefit to our senior citizen customers 60 years of age or older that fall between 0-250 percent of the federal poverty level and is in need of financial assistance with gas residential utility charges. Learn more at https://www.nipsco.com/bills-and-payments/financial-support/income-eligible-assistance-programs

Recognizing the diverse needs of its customers, NIPSCO also facilitates access to local resources such as Township Trustees, who administer limited energy assistance funds. These trustees can offer individualized support to eligible residents, further enhancing the reach and effectiveness of NIPSCO's assistance efforts. Additionally, renters in need of support can avail themselves of the Indiana Emergency Rental Assistance (IERA) Program, which provides comprehensive rental and utility assistance for up to 18 months.

In addition to helping customers to manage their bill NIPSCO also promotes energy efficiency. This is not only good for customers, but it can also play an important role in helping ensure that we can meet future energy needs. NIPSCO offers a variety of programs to help residential and business customers save energy. The programs are tailored to customers and designed to provide education and identify opportunities to ensure energy savings. Since 2010, NIPSCO customers have saved more than 1.7 million megawatt hours of electricity by participating in the range of energy efficiency programs offered by NIPSCO. Technologies continue to change, and it's important that we constantly evaluate our program and measure offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings.

By proactively engaging with customers and offering tailored assistance programs, NIPSCO continues to demonstrate its commitment to supporting community well-being and ensuring energy affordability during challenging times. Through dedicated website landing pages, informative fact sheets, timely bill inserts, strategic media placements, and more, NIPSCO ensures that customers are well-informed and empowered to access the full range of assistance programs available to them, supporting their energy needs with clarity and transparency.

10.2 Community Partnerships

10.2.1 Community Advisory Panels

Another NIPSCO engagement avenue with customers and stakeholders is the use of CAPs, which serve as a forum to discuss new company initiatives and programs as well as to educate and facilitate feedback regarding service and other NIPSCO-related matters in our communities. NIPSCO has five regional CAPs across the Company's northern Indiana footprint. CAPs are composed of individual customers and local government and community leaders representing a diverse, broad cross-section of NIPSCO customers. Meetings are held three times a year featuring internal and external presenters to help the company identify communication improvements, highlight information about helpful customer programs and outreach efforts, and create a channel for ongoing dialogue and feedback. NIPSCO senior management meets with each of the regional CAPs once a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues.

10.3 Customer Programs

10.3.1 Feed-in Tariff (FIT)

NIPSCO's FIT Phase I was approved on July 13, 2011, in Cause No. 43922. Implementation began immediately as a three-year pilot program with a 30 MW capacity cap. Phase I offered a higher rate to participants selling electricity than the retail electric rate in the current approved sales tariffs and provided an incentive to encourage development of renewable generating resources. The pilot program was designed to help maximize the development of renewable energy in Indiana, which welcomed biomass, wind and solar resources. The FIT provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a RPPA. Participating customers receive payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- An Interconnection Agreement and Renewable Power Purchase Agreement are required to reserve capacity or enter the queue.

- The customer is responsible for interconnection fees and installation costs in accordance with the Indiana Administrative Code.

- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with the Interconnection Agreement.

Phase I concluded in March 2015 with a total subscription of 29.7 MW and is summarized in Table 10-1.

Table 10-1: FIT Phase I In-Service

Technology	Total FIT (kW)
Biomass	14,348
Solar (large)	14,500
Solar (small)	690
Wind (large)	150
Wind (small)	10
New Hydro	0
Total	**29,698**

NIPSCO's FIT Phase II was approved on February 4, 2015, in Cause No. 44393. NIPSCO released Phase II, Allocation I of the FIT program in March 2015 and Phase II, Allocation II in March 2017. Phase II allows for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW. Table 10-2 shows the subscription for Phase II as of July 2024.

Table 10-2: FIT Phase II Project Totals

Technology	In-Service (kW)	Queue (kW)	Total FIT (kW)
Micro Solar	436	43	479
Intermediate Solar	6,370	200	6,570
Micro Wind	20	0	20
Intermediate Wind	0	0	0
Biomass	0	0	0
Total	6,826	243	7,069

With over 36 MW of capacity currently interconnected in the FIT program, as of Dec. 31, 2023, NIPSCO had a total metered generation from customers selling electricity of 1,188,625 MWh. Despite continued interest in the FIT program, there are no plans to offer another FIT program in the future. Table 10-3 shows the annual production and growth by technology segment.

Table 10-3: Annual Production by Technology – Generation (MWh)

Year	Biomass	Intermediate Solar	Micro Solar	Intermediate Wind	Micro Wind	Total
2011	6,219,791	0	0	0	0	6,219,791
2012	19,152,432	433,758	118,895	0	3,588	19,708,673
2013	31,602,728	15,789,457	471,806	90,113	15,721	47,969,825
2014	49,916,700	21,665,115	718,758	165,880	12,051	72,478,504
2015	81,369,723	22,436,103	818,332	217,949	9,462	104,851,569
2016	83,552,339	22,696,839	825,066	165,593	8,019	107,247,856
2017	89,486,440	24,391,349	848,789	167,807	8,487	114,902,872
2018	94,942,135	27,450,274	848,789	179,797	8,487	123,429,482
2019	94,551,873	26,707,084	857,037	142,631	8,381	122,267,006
2020	96,144,048	30,345,387	899,064	115,177	7,880	127,511,556
2021	96,195,974	30,761,852	1,047,838	88,207	4,333	128,098,205
2022	77,891,838	27,893,285	1,109,705	118,714	4,924	107,018,466
2023	79,614,091	26,016,366	1,192,461	95,105	3,515	106,921,537
Total	900,640,112	276,586,868	9,756,540	1,546,973	94,848	1,188,625,342

10.3.2 Excess Distributed Generation Tariff

The Net Metering program ended for new customer applications for non-residential customers on Oct. 1, 2021, and for residential customers on June 20, 2022. The EDG Tariff replaced Net Metering. NIPSCO's EDG Tariff allows customers to install renewable energy generation to offset all or part of their own electricity requirements. An EDG credit is applied to a customer's bill if a customer generates more energy than they consume. If a customer produces more than they need, they receive a utility bill credit that can be applied to reduce their bill in the amount of 125% of market priced power for all excess distributed generation. Production is measured on a per kWh basis. To be eligible, a customer must be in good standing and operate a solar, wind, biomass or hydro generating facility that has a nameplate capacity of less than or equal to 1 MW. NIPSCO follows the rules and guidelines in the Indiana Administrative Code regarding EDG and the interconnection process. Customers with a fully executed EDG Agreement and Interconnection Agreement receive credit for generation provided to NIPSCO above their own usage requirements. The current number of EDG customers as of Dec. 31, 2023, is shown in Figure 10-1.

Figure 10-1: Classification of EDG

Non-Residential				Residential			
Number Customers	Total Capacity	Battery Storage		Number Customers	Total Capacity	Battery Storage	
		kW	kWh			kW	kWh
23	2583.63	4.5	9	83	856.86	99.8	200.8

10.3.3 Green Power Rider (GPR) Program

NIPSCO's GPR program was approved on Dec. 19, 2012, in Cause No. 44198. NIPSCO's request for an extension of its GPR program, with certain modifications and as a component of NIPSCO's approved tariff on a non-pilot basis, was approved on Dec. 30, 2014, in Cause No. 44520. The GPR Program is a voluntary program that allows customers to designate a portion or all their monthly electric usage that they want to be renewable energy. Customers can enroll online or by calling NIPSCO.

Green power is energy generated from renewable and/or environmentally friendly sources or a combination of both, which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of green power include solar, wind, geothermal or hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green power includes the purchase of RECs from the sources described above. For the GPR program, NIPSCO's residential electric customers can designate 25%, 50% or 100% of their total electricity usage they would like to be renewable energy. In addition to those options, NIPSCO's nonresidential customers also have the option to designate 5% or 10% of their total electricity usage they would like to be renewable energy. As of Dec. 31, 2024, 1,600 customers were participating in the GPR Program. Figure 10-2 shows the breakdown among residential customers as of Dec. 31, 2023.

Figure 10-2 GPR Program Residential Customer Count

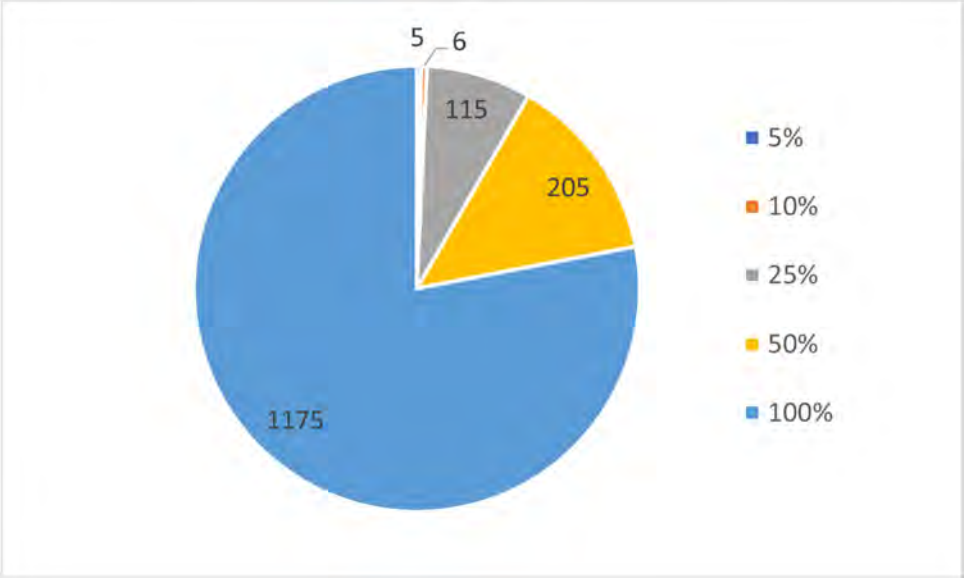
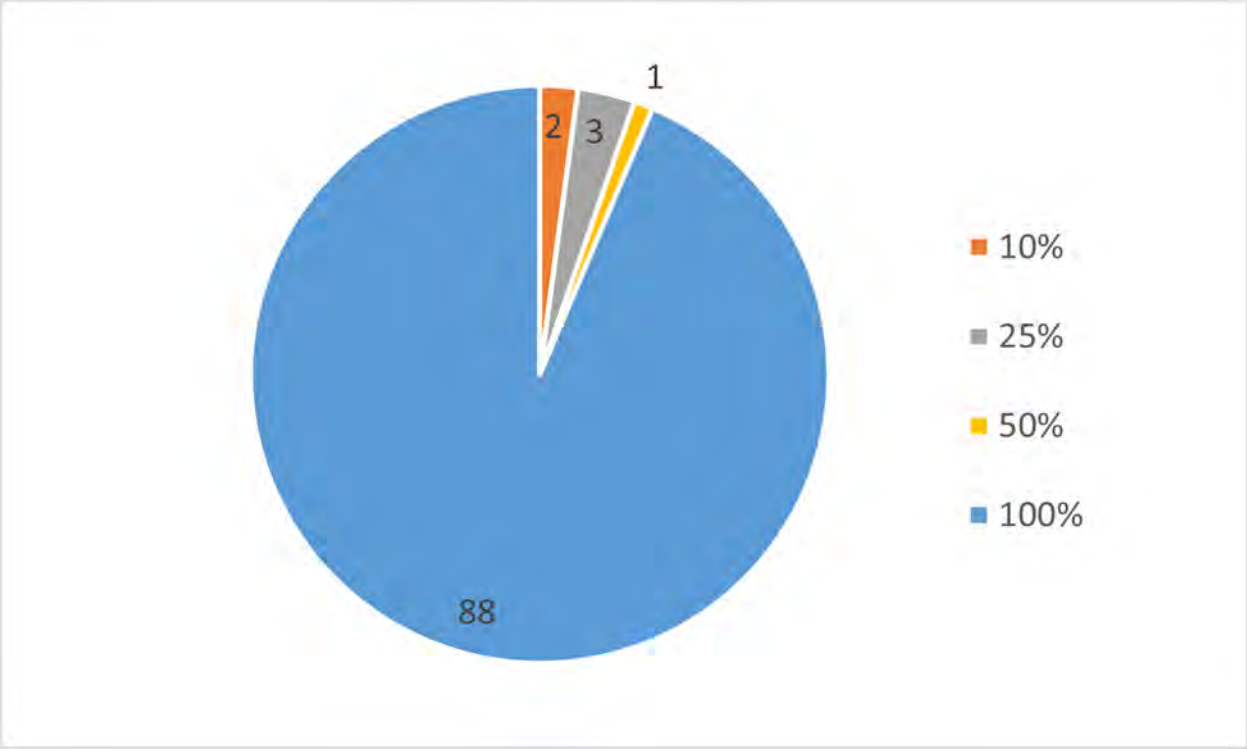


Figure 10-3 shows the breakdown of commercial and industrial customers as of December 31, 2023.

Figure 10-3: GPR Program Commercial Customer Count



NIPSCO's GPR program from Jan. 1 through Dec. 31, 2023, accounted for 376,983,386 kWh of energy consumption designated as green power. Residential customers accounted for 10,119,490 kWh of energy consumption, and nonresidential customers accounted for 366,869,896 kWh of energy consumption of designated green power. For both residential and commercial customers, the majority of the GPR program enrollments designate 100% of their energy as green power. Table 10-4 shows the energy consumption designated as Green Power for participating customers, by rate type, for the period Jan. 1 through Dec. 31, 2023.

Table 10-4: Green Power Customers by Rate Type (kWh)

2023	Residential	Nonresidential
January	955,852	35,769,593
February	785,049	28,138,645
March	755,862	39,428,393
April	693,840	27,357,435
May	648,145	41,867,313
June	792,617	40,902,897
July	1,077,787	33,823,421
August	1,133,238	36,111,684
September	1,041,851	35,284,240
October	707,356	20,234,459
November	692,436	10,722,534
December	835,459	17,223,285
Total	10,119,490	366,863,896

Participating customers are billed under their current applicable rates, with a separate line item showing the premium to participate in the GPR program. This premium is calculated by multiplying the GPR rate by the kWhs the customer specifies to be subject to the GPR. Table 10-5 shows the green power premiums applicable during the period July 1, 2021, through June 30, 2025.

Table 10-5: Green Power Rates

July 2021 to June 2022	July 2022 to June 2023	July 2023 to June 2024	July 2024 to June 2025
$0.005439	$0.003092	$0.001992	$0.000932

10.3.4 Green Path Rider Program

NIPSCO's Green Path Rider Program was approved on Nov. 23, 2022, in Cause No. 45730. Green Path is a voluntary program which allows customers to designate a portion or all their monthly natural gas usage to be supplemented by a combination of RNG and carbon offsets to allow them to offset emissions from their natural gas usage. Customers can enroll online or by calling NIPSCO.

Carbon offsets purchased for NIPSCO are on a global scale and are registered, recognized, and retired by such registries as Verra; Climate Action Reserve; American Carbon Registry; UN CDP; or The Gold Standard. M-RETS®, a non-profit organization that utilizes a web-based system, tracks and confirms the RNG attributes NIPSCO acquires. Both NIPSCO residential and non-residential customers can elect to designate 25%, 50%, or 100% of their monthly natural gas therm usage to participate in the Green Path program.

Customers shall pay a fixed volumetric charge reflecting the cost of the RNG environmental attributes and carbon offsets needed to reflect the selected 25%, 50% or 100% reduction in emissions. The fixed volumetric charge shall be reviewed and may be adjusted annually by the Company and approved by the Commission. The fixed volumetric charges set forth below are effective for bills rendered for the billing month of January 2024, and will remain in place until new fixed volumetric charges are approved by the Commission in a subsequent proceeding:

- 25% Emissions Reduction $0.05625 per Therm for all Therms used per month
- 50% Emissions Reduction $0.1125 per Therm for all Therms used per month
- 100% Emissions Reduction (Net Zero) $0.225 per Therm for all Therms used per month

As of July 2024, NIPSCO has 415 residential customers participating in Green Path and 5 non-residential customers for a combined total of 420 customers.

Count of CUSTOMER ACCOUNT	**Column Labels**			
Row Labels	**25**	**50**	**100**	**Grand Total**
311 - Res	140	99	176	415
321 - Com		1	4	5
Grand Total	**140**	**100**	**180**	**420**

10.3.5 Transportation Decarbonization: DC Fast charging stations & IDEM Grant

NIPSCO has completed installation of 8 EV Fast Charging Stations as part of two grant awards: (1) an IDEM grant award being managed as part of the Indiana Volkswagen Environmental Mitigation Trust Fund Committee and (2) a grant award from the White County Economic Development Committee. In addition, NIPSCO was selected as an award winner for two NEVI site grants being managed by INDOT. These two NEVI grants will be used to expand one of the currently existing DC Fast Charging Stations in Merrillville, Indiana and the other will be used to install a new station in Gary, Indiana, which will bring the total NIPSCO owned EV Fast Charging Stations to nine once completed. In addition, NIPSCO continues to seek and explore additional funding opportunities to assist with transportation electrification efforts for our customers.

10.3.6 Advanced Metering Infrastructure (AMI)

In 2024, NIPSCO announced plans to enhance electric and gas metering systems by deploying AMI technology. The initiative aims to upgrade services for customers across the region. The deployment will cover 490,000 electric customers over the next three years and 870,000 gas customers throughout NIPSCO's service area.

Installation of electric AMI meters and gas AMI communications devices has already begun. As of November 2024, approximately 78,000 electric AMI meters and approximately 61,000 gas AMI communications devices have already been installed in NIPSCO's service area, marking a significant step forward in the modernization effort. Installation of gas AMI communications devices is expected to be completed by the end of 2026 and the rollout of electric AMI meters is expected to be completed by the end of 2027.

Integration of AMI technology will allow NIPSCO to provide improved responses for outages and emergencies and lay the foundation for greater energy efficiency offerings, cost savings, and more granular billing information for customers. NIPSCO will also be able to read and access customer meters remotely.

10.3.7 Supporting Economic Growth

NIPSCO partners with community leaders and state, regional, and local economic development organizations to attract and support the expansion of new and existing businesses and to help create more jobs across the NIPSCO service territory. In addition to being one of the largest employers in the region, NIPSCO invests $1.1 million in economic development efforts each year, which has resulted in 88 new businesses or expansions and 11,000 local jobs in the past 10 years. The NIPSCO Economic Development team participates in local and regional economic development boards and helps promote and market our service territory for new investment. NIPSCO's Economic Development team works closely with the state of Indiana, local government, economic development professionals, and the real estate/developer community to help attract and land key investments that create jobs and increase local tax revenue in the communities we serve.

NIPSCO's Economic Development Rider 577 allows NIPSCO to offer an incentive for new investment within our service territory. This rate can be offered on existing tariff services for qualifying projects that bring new jobs and investment from outside the NIPSCO service territory. When coupled with local and state incentives, a powerful package is created with often positive results.

10.3.8 Supplier Diversity

Cultivating a diverse pipeline of suppliers helps bring innovative ideas and processes, a competitive advantage, and other benefits to NIPSCO's communities. NIPSCO has created a supplier diversity program that strengthens and widens the playing field for qualified suppliers who are typically underutilized in the supply chain of a large corporation.

In 2023, NIPSCO's direct supplier spending in Indiana was $1.5 billion. Of that, $204.6 million was spent on diverse businesses and $57.5 million was spent with diverse subcontractors.

10.3.9 Workforce Development

NIPSCO continues to lead efforts and partnerships focused on workforce development – both for the current and future workforce generations. Some recent highlights include:

- **Ivy Tech Power Your Future Program & FLEX Lab:** NIPSCO has partnered closely with Ivy Tech Community College to drive workforce innovation, notably through initiatives such as the "Power Your Future" program. This collaborative effort was bolstered by a $50,000 grant from the NISOURCE Foundation to Ivy Tech - Lake County Campus, aimed at inspiring diverse students in grades 7 to 12 to pursue careers in the energy and industrial technology fields. This initiative complements NIPSCO's sponsorship of the FLEX Lab within Ivy Tech's Energy Technology Program in Valparaiso, where students gain hands-on training in essential skills like climbing techniques and industrial wiring. Upon completion, graduates earn an associate degree in Energy Technology and a technical certificate in Electric Line Technology, directly preparing them for roles at NIPSCO. Beyond financial support, NIPSCO encourages its employees to engage directly with local classrooms across Lake County, sharing personal career journeys and insights. This volunteer effort not only enriches educational experiences but also fosters a future workforce well-equipped for the utility industry's demands. By investing in education and community involvement, NIPSCO and Ivy Tech are collaboratively shaping a promising future for aspiring professionals in Indiana's energy sector, addressing critical workforce needs and highlighting the diverse and rewarding career opportunities available.

- **NIPSCO Energy Academy:** Started in 2014, the NIPSCO Energy Academy program is a partnership designed to prepare area students for high-demand jobs in the electronics, energy, and utility industries. It is the first initiative of its kind in Indiana, and it will serve students from Michigan City High School, LaPorte High School, New Prairie High School, South Central High School, LaCrosse High School, and Westville High School.

- **IN-POWER Youth Mentoring Program:** In its 14th year, NIPSCO's IN-POWER Youth Mentoring Program has been a unique mentoring program for local high school students that takes a holistic approach to developing a more highly skilled future workforce in the energy sector. The program was expanded with IN-POWER STEM PLUS, designed to give 7th and 8th grade students a firsthand experience on gas and electric safety while teaching them about the various aspects of STEM needed in the energy sector. NIPSCO employees and American Association of Blacks in Energy Indiana members serve as mentors and instructors. Participants receive college credits, unique mentoring and internships, among other opportunities.

- **NIPSCO Energy Ambassador Program:** The NIPSCO Energy Ambassador program, in partnership with the Urban League of Northwest Indiana, Inc., is a college- and career- readiness program that has been going strong for seven years. This opportunity invites 11th and 12th grade students throughout northwest Indiana to participate in virtual workshops, field trips, meetups, community engagement and activities designed to educate students about NIPSCO's operations and encourage STEM learning.

- **Free Gas Training Safety Event for Local Fire Departments:** NIPSCO plays a vital role in community safety by offering comprehensive natural gas safety training to fire departments across NIPSCO's service area. Since 2018, nearly all fire departments—approximately 99%—have participated in this initiative, benefiting around 8,000 first responders. This training equips firefighters with essential skills and knowledge to effectively handle natural gas emergencies, covering topics such as the gas distribution system, characteristics of natural gas, and safe response tactics. Led by experienced trainers who are former firefighters themselves, the program includes live demonstrations to illustrate potential hazards like ignitions and explosions. NIPSCO's commitment to continuous education and preparedness not only ensures compliance with safety standards but also fosters strong community partnerships, enhancing overall safety and response capabilities in the region.

- **OJT Coach Program for Power Delivery:** Launched in 2021, NIPSCO's On the Job Training (OJT) coach program for Power Delivery enhances workforce development by providing rigorous training and support for field employees. This program builds on an existing structured OJT model and includes collaboration with Northwest Lineman College. The training combines 70% hands-on field learning with structured instructor-led sessions, facilitated through iPads for easy access to training materials. OJT coaches reinforce formal instruction and ensure safety and standards compliance through regular knowledge checks and performance evaluations. This program aims to develop critical competencies in apprentices, contributing to their safe and effective performance in the field.

- **Mobile Unit Partnership with Workforce Innovations:** The launch of a new mobile unit, made possible by a $100,000 grant from the NIPSCO/NiSource Charitable Foundation, is a significant development by the United Way of Northwest Indiana in partnership with the Center of Workforce Innovations (CWI). This mobile unit is part of the Level Up program, which aims to assist struggling working individuals in developing new skills, stabilizing their finances, and finding better-paying jobs. The unit addresses barriers such as lack of transportation and limited free time by bringing resources directly to communities in need. The mobile unit visits libraries, career events, community gatherings, and client-serving organizations across Northwest Indiana. Other goals of the program include reducing social-emotional barriers for students, increasing students' interest in STEM careers, boosting self-esteem and supporting educational goals.

- **Junior Achievement Support:** NIPSCO provides annual support for classroom business education programs through both contributions and volunteer instructors across NIPSCO's service area. NIPSCO has supported a "JA Day" in a local Hammond and East Chicago school systems where NIPSCO employees go into a local school and deliver JA curriculum. NIPSCO employees also participate in local career fairs through JA, showing local students what kind of job opportunities there are throughout the region. In 2024, NIPSCO partnered with JA to support the

launch of virtual platform called Metaversity that will allow students to learn about different careers in a virtual interactive environment.

- **Girl Scouts Engineering Day:** For more than ten years, NIPSCO has hosted more than area girls from kindergarten to 5th grade for the annual Introduce a Girl to Engineering Day. The girls come from local Girl Scout troops, community members along with some young relatives of NIPSCO and NiSource employees. The five-hour event is part of the company's efforts to help build the next generation of female leaders, support local communities and provide opportunities for local students interested in STEM-related careers. The event is organized by the employee resource group Developing and Advancing Women at NiSource.

10.3.10 Corporate Citizenship

At NIPSCO, being a responsible corporate citizen is at the core of who we are. We are committed to building a better future, fueled by the belief that by coming together, we can improve the lives of those who need it most. Each year, NIPSCO donates time, money and other resources to hundreds of local philanthropic programs and organizations across its 32-county service area, focusing on:

- Safety
- Economic and workforce development
- Environmental stewardship
- STEM and energy education
- Basic needs and hardship assistance

Through these programs and partnerships, NIPSCO is working hard with its communities to build a brighter future for years to come.

10.3.11 Targeted Grants

NIPSCO helps fund environmental projects and programs through its annual Environmental Action Grant. To date, NIPSCO has helped 124 projects come to fruition across northern Indiana. The 15 projects funded in 2023 by the NiSource Charitable Foundation provided funds to projects focused on Monarch butterflies, habitat restoration, youth outdoor nature education and sustainability programming. Many funded projects and programs included a significant volunteer and community engagement component, encouraging community members to give back through environmental stewardship projects.

In its sixth year, NIPSCO's Public Safety Education and Training Action Grant provided funding to 16 local nonprofit organizations and first responders with their public safety education and training across northern Indiana. Some of the projects included distribution of carbon

monoxide detectors to residents, carbon monoxide educational training and lithium-ion battery response training.

In 2023, together with the NiSource Charitable Foundation and direct employee contributions, NIPSCO donated over $2.4 million to more than 250 local non-profits and community organizations and volunteered more than 2,700 service hours throughout the NIPSCO service territory.

A highlight of that effort includes NIPSCO's annual Charity of Choice campaign, a collaborative initiative led by employees, aiming to make a meaningful impact through volunteer work in diverse community projects throughout NIPSCO's service area. NIPSCO employees accumulated 800 volunteer hours for local organizations. Recent benefactors and causes selected by employees have included local food banks, a domestic violence shelter, Humane Indiana, a United Way chapter, Boys & Girls Clubs, to name a few.

10.3.12 Charitable Giving

In 2023, NIPSCO and the NiSource Charitable Foundation provided funding to organizations focused on making positive contributions to the communities we are privileged to serve.

- $100,000 to United Way of Northwest Indiana: This donation provided collaborative partnership with the Center of Workforce Innovations to develop two handicap-accessible mobile resource centers. This project combines resources from both agencies to make a strong impact in our communities.

- $50,000 to Believe in a Dream: Believe in a Dream received funds to scale up its Pave The Path program. The program focuses on youth development, empowering high school students across Northeast Indiana to discover their strengths, and personal brand, and explore leadership experiences through community connections.

- $50,000 to Hilltop Neighborhood House: Funds will be used to build the Hilltop Mission Kitchen, a community soup kitchen to serve meals to food-insecure people living in Valparaiso and provide cooking and life skills classes for clients. NIPSCO manager and Hilltop board member, Ryan Hutnick, leveraged this donation with a volunteer event to install board siding on the facility.

- $35,000 to Purdue Northwest University: Purdue Northwest University used the funds to host the Summer Innovation Makers STEM Camp in July 2023. This week-long camp introduced Northwest Indiana high school sophomores and juniors to entrepreneurship and experiential learning through inventing, building a business and pitching investors with access to the maker lab's cutting-edge technology.

- $25,000 to the Nature Conservancy: Funds were used to create an outdoor pavilion and two public viewing platforms to support Kankakee Sand's Welcome Center and

bison viewing initiative. There are over 100 bison grazing and roaming in the Kankakee Sands Reserve, supporting biodiversity and restoring northwest Indiana's prairie.

Section 11. Compliance with IRP Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents: (1) The integrated resource plan.	Submitted via email on December 9, 2024
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP. (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If the utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.	Confidential Appendix D
(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) the IRP public advisory process; and (vi) any additional details the commission staff may request.	Executive Summary

Rule	Section(s)
(B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	
(d) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following information: (1) The name and addresses of known entities considered by the utility to be interested parties. (2) A statement that the utility has sent known interested parties, electronically or by deposit in the United States mail, first class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information: (A) A general description of the subject matter of the submitted IRP. (B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 90 days of the IRP submittal. An interested party includes a business, organization, or particular customer that participated in the utility's previous public advisory process or submitted comments on the utility's previous IRP. A utility is not required to separately notify other customers. (3) A statement that the utility served a copy of the documents submitted under subsection (c) on the OUCC.	Transmittal Letter
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) Indiana Municipal Power Agency; (2) Hoosier Energy Rural Electric Cooperative; (3) Wabash Valley Power Association. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within fifteen (15) business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff. (d) The utility retains full responsibility for the content of its IRP.	N/A
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in	Section 2.1 Appendix A

Rule	Section(s)
the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection. (2) The utility may hold additional meetings. (3) The schedule for meetings shall: (A) be determined by the utility (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP. (4) The utility or its designee shall: (A) chair the participation process (B) schedule meetings; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen (15) calendar days following each meeting; (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility. (6) The utility shall take reasonable steps to notify: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC; of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	

Rule	Section(s)
(a) The commission or its staff may host an annual technical conference to facilitate: (1) identifying contemporary issues; (2) identifying best practices to manage contemporary issues; and (3) instituting a standardized IRP format. (b) The agenda of the technical conference shall be set by the commission staff. (c) Utilities, the OUCC, and interested parties may request commission staff include specific contemporary issues and presenters. (d) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed.	N/A
(e) Utilities shall address the designated contemporary issues in the next IRP if the contemporary issues were designated by the director at least one (1) year prior to the submittal date of the utility's IRP.	Section 2.2.1
170 IAC 4-7-4: Integrated Resource Plan Contents	
An IRP must include the following:	
(1) At least a twenty (20) year future period for predicted or forecasted analyses.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Section 3.3 Section 3.4 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.9
(3) At least three (3) alternative forecast scenarios of peak demand and energy usage in compliance with section 5(b) of this rule.	Section 8.4
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	Section 4.1 Section 4.2 Section 5.1 Section 6 Section 7.3 Confidential Appendix C
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Section 5

Rule	Section(s)
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	
(7) The resource screening analysis and resource summary table required in section 7 of this rule.	Section 4.6
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.	Section 9.1 Section 9.2 Section 9.3 Confidential Appendix D
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Section 9.2 Section 9.3 Section 9.4
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Section 1.1 Section 9.5
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Section 2 Section 3.3 Section 3.4 Section 3.5 Section 3.6 Section 4.1 Section 4.2 Section 4.3 Section 4.6 Section 5.1 Section 5.2 Section 5.3 Section 7.3 Section 8.2 Section 8.5 Section 9.2 Section 9.3 Appendix A Confidential Appendix D
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data.	Confidential Appendix D

Rule	Section(s)
The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as comma separated value or excel spreadsheet file.	
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Section 3 See Note 1
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Section 3
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration, (B) end-use saturation rates, and (C) end-use electricity consumption patterns.	See Note 2
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 3 Section 10
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e) of this rule.	Section 2.2
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	Section 3.5 Section 3.8 Section 10
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Appendix A
(20) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 2
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	Section 7

Rule	Section(s)
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 7.3 Section 7.4 Section 8.2.3
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness, (B) rate impacts, (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	Section 9.2
(25) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 solicits stakeholder input regarding the inclusion and describes the input received; (ii) Future resources have obtained the necessary regulatory approvals; (iii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	Section 8.2 Section 9.3
(26) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 8.4 Section 9.3

Rule	Section(s)
(27) A brief description of the models, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.	Confidential Appendix C
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	Section 2.2 Section 3.2 Section 5.2 Section 8.1 Section 9.3 Appendix B
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost.	Section 5.2 Appendix B

Rule	Section(s)
(D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.	
(30) A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues (C) A description of how stakeholder input was used in developing the IRP.	Section 2.1 Appendix A
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 5 Appendix B
170 IAC 4-7-5: Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	0 Confidential Appendix D
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	Section 3
(3) Actual and weather normalized energy and demand levels.	Section 3.7
(4) A discussion of methods and processes used to weather normalize.	Section 3.3.1
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Section 3.7
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes, rate classes, or both. (C) Firm wholesale power sales.	Section 3.2 Section 3.3
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2 Section 3.3
(8) Justification for the selected forecasting methodology.	0

Rule	Section(s)
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	Section 2.2
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	No Response Needed
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts. (c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 3.8
(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process.	Section 3.2 Section 2.2.2
170 IAC 4-7-6: Resource Assessment	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	Section 4.1
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.1

Rule	Section(s)
(3) A fuel price forecast by generating unit.	Section 8.2 Confidential Appendix D
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	Section 4.1
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses, (ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	Section 5.2 Section 6.1
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivisions (1) through (4) and in subdivision (6) shall be provided for each year of the future planning period.	Section 3.2 Section 5 Appendix B
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	Section 3.1 Section 3.5.3 Section 3.8 Section 5.2
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics, and parameters. (B) The method by which the costs, characteristics, and other parameters of the demand-side resource are determined. (C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings.	Section 5 Appendix B See Note 3

Rule	Section(s)
(E) The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost. (C) A description of significant environmental effects, including the following: (i) air emissions. (ii) solid waste disposal. (iii) hazardous waste and subsequent disposal. (iv) water consumption and discharge.	Section 4.1 Section 4.3 Section 4.5 Section 4.6
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following: (A) The type of transmission resource, including whether the resource consists of one (1) of the following: (i) new projects. (ii) upgrades to transmission facilities. (iii) efficiency improvements. (iv) smart grid technology. (B) A description of the timing, types of expansion, and alternative options considered.	Section 6.1 Section 6.2
(C) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.6
(D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 6.1
(D) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and	Section 6.1

Rule	Section(s)
(ii) RTO planning and implementation processes affect the IRP.	
170 IAC 4-7-7: Selection of Resources	
(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 4.6 Section 5.2 Section 5.3 Appendix B
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from existing and future resources in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Section 9.1
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(26) of this rule. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2 Section 9.3 Confidential Appendix D
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio.	Section 9.4
(2) Identification of the standards of reliability.	Section 9.2 Section 9.3.3.1

Rule	Section(s)
(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.3
(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 9.2 Section 9.3
(5) An analysis showing the preferred resource portfolio utilizes, supply-side resources and demand-side resources that safely, reliably, efficiently, and cost-effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	Section 9.3
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	Appendix B
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Section 9.3 Section 9.4 Confidential Appendix D
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs;	Section 9.4

Rule	Section(s)
(vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(9) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Executive Summary Section 9.4
170 IAC 4-7-9: Short Term Action Plan	
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule. (b) The short term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(10) of this rule, where the utility must take action or incur expenses during the three (3) year period. (c) The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10 and	Section 1.1 Section 9.4 Section 9.5 Confidential Appendix D

Rule	Section(s)
170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives. (3) The implementation schedule for the preferred resource portfolio. (4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	
Note 1: NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumption patterns by DSM program. The savings associated with DSM programs are gauged and claimed based on various TRMs, including the Indiana TRM, and the DSM programs are evaluated by program year by a third party EM&V administrator. NIPSCO will continue to consider its options. NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumptions patterns by end use.	
Note 2: As part of its DSM functions, DSM programs are evaluated by program year by a third party EM&V administrator. As part of the EM&V process, the administrator surveys a sample of customers who have and have not participated in NIPSCO's DSM program. NIPSCO conducted an MPS (see Appendix B) that includes primary data. In addition, NIPSCO has previously completed lighting and market effect studies. NIPSCO used customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns as part of its updated MPS.	
Note 3: Customer bill impacts are calculated directly utilizing the customer rate and the savings of each measure/participant. Appropriate escalators and discount rates are used to determine the NPV of these savings and then Aggregated across all measures/participants. Incentives are also included in the cost benefit analysis as an input on a per participant/measure basis. Appropriate escalators and discount rates are applied and the NPV calculated.	

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 101
Schahfer Title V Permit Modification,
February 2025

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

To:	Interested Parties
Date:	February 4, 2025
From:	Jenny Acker, Chief Permits Branch Office of Air Quality
Source Name:	Northern Indiana Public Service Company LLC RM Schahfer Generating Station
Permit Level:	TV Significant Permit Modification
Permit Number:	073-48085-00008
Source Location:	2723 E 1500 N, Wheatfield, IN 46392
Type of Action Taken:	Modification at an existing source

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the matter referenced above.

The final decision is available on the IDEM website at: https://www.in.gov/apps/idem/caats/
To view the document, choose Search Option **by Permit Number**, then enter permit 48085. This search will also provide the application received date, **draft permit** public notice start and end date, **proposed permit** EPA review period start and end date, and **final** permit issuance date.

The final decision is also available via IDEM's Virtual File Cabinet (VFC). Please go to: https://www.in.gov/idem and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

(continues on next page)

If you would like to request a paper copy of the permit document, please contact IDEM's Office of Records Management:

IDEM - Office of Records Management
Indiana Government Center North
100 North Senate Avenue
Indianapolis, IN 46204-2251
Phone: (317) 232-8667
Fax: (317) 233-6647
Email: IDEMFILEROOM@idem.in.gov

Pursuant to IC 13-17-3-4 and 326 IAC 2, this permit modification is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-7-3 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to Indiana Office of Administrative Law Proceedings, 100 N. Senate Avenue Suite N802, Indianapolis, IN 46204, **within eighteen (18) days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Indiana Office of Administrative Law Proceedings (OALP); or
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OALP by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OALP by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

Pursuant to 326 IAC 2-7-18(d), any person may petition the U.S. EPA to object to the issuance of an initial Title V operating permit, permit renewal, or permit modification within sixty (60) days of the end of the forty-five (45) day EPA review period. Such an objection must be based only on issues that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impractible to raise such issues, or if the grounds for such objection arose after the comment period.

The EPA requests that you file Title V petitions electronically through the Central Data Exchange. To do so, please go to: https://cdx.epa.gov/ .

If you tried but you are unable to use the Central Data Exchange to file your petition, the EPA requests that you send your petition and associated attachments via email to: titleVpetitions@epa.gov.

If you have made every effort to electronically submit your petition but are simply unable to successfully do so, please submit a hardcopy of your petition to the following address:

US EPA
Office of Air Quality Planning and Standards
Air Quality Policy Division
Operating Permits Group Leader
109 T.W. Alexander Dr. (C-504-01)
Research Triangle Park, NC 27711

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures
Decision-Title V-Mod 1/13/25

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun, *Governor*

February 4, 2025

Edward D. Pierce
Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station
2755 Raystone Drive
Valparaiso, IN 46383

Re: 073-48085-00008
Significant Permit Modification

Dear Mr. Pierce:

Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station was issued Part 70 Operating Permit Renewal No. T073-45762-00008 on November 13, 2024 for a a stationary electric utility generating station located at 2723 East 1500 North, Wheatfield, Indiana 46392. An application requesting changes to this permit was received on June 17, 2024. Pursuant to the provisions of 326 IAC 2-7-12, a Significant Permit Modification to this permit is hereby approved as described in the attached Technical Support Document.

Please find attached the entire Part 70 Operating Permit as modified, including the following new attachment(s):

Attachment F: 40 CFR 60, Subpart IIII, Stationary Compression Ignition Internal Combustion Engines [*revised]*
Attachment H: 40 CFR 63, Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines [*revised]*
Attachment I: 40 CFR 60, Subpart KKKK, Stationary Combustion Turbines [*new]*
Attachment J: 40 CFR 60, Subpart TTTTa, Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units [*new]*

The permit references the below listed attachment(s). Since these attachments have been provided in previously issued approvals for this source, IDEM OAQ has not included a copy of these attachments with this modification:

Attachment A: Decree Paragraphs and Tables
Attachment B: Northern Indiana Public Service Company LLC - Consent Decree
Attachment C: 40 CFR 60, Subpart Da, Electric Utility Steam Generating Units
Attachment D: 40 CFR 60, Subpart Y, Coal Preparation and Processing Plants Requirements
Attachment E: 40 CFR 60, Subpart GG, Stationary Gas Turbines Requirements
Attachment G: 40 CFR 63, Subpart UUUUU, : Coal- and Oil-Fired Electric Utility Steam Generating Units

Previously issued approvals for this source containing these attachments are available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

Previously issued approvals for this source are also available via IDEM's Virtual File Cabinet (VFC). To access VFC, please go to: https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria.

Federal rules under Title 40 of United States Code of Federal Regulations may also be found on the U.S. Government Printing Office's Electronic Code of Federal Regulations (eCFR) website, located on the Internet at: http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40tab_02.tpl.

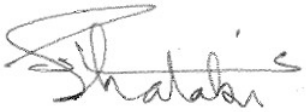
A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. A copy of the application and permit is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria. To find documents related to this air permit, click on "Advanced Search", specify "OAQ" in the Program search field, specify the five-digit permit number "48085" in the Permit # search field, then click the Search button at the top or bottom of the webpage.

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5.

If you have any questions regarding this matter, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

Sincerely,



Ghassan Shalabi, Section Chief
Permits Branch
Office of Air Quality

Attachments: Modified Permit and Technical Support Document
cc: File - Jasper County
Jasper County Health Department
U.S. EPA, Region 5
Compliance and Enforcement Branch

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun, *Governor*

Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station

2723 East 1500 North
Wheatfield, Indiana 46392

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

Operation Permit No.: T073-45762-00008 Master Agency Interest ID.: 11840	
Issued by: Original signed by: Ghassan Shalabi, Section Chief Permits Branch, Office of Air Quality	Issuance Date: November 13, 2023 Expiration Date: November 13, 2028

Significant Permit Modification No.: 073-48085-00008	
Issued by: Madhima Das for Ghassan Shalabi, Section Chief Permits Branch Office of Air Quality	Issuance Date: February 4, 2025 Expiration Date: November 13, 2028

Visit on.IN.gov/survey or scan the QR code to provide feedback.
We appreciate your input!
Letterhead IN/OAQ R.01 2024

TABLE OF CONTENTS

SECTION A SOURCE SUMMARY 9

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]
A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]
A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]
A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

SECTION B GENERAL CONDITIONS 14

B.1 Definitions [326 IAC 2-7-1]
B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]
B.3 Term of Conditions [326 IAC 2-1.1-9.5]
B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]
B.5 Severability [326 IAC 2-7-5(5)]
B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]
B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]
B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]
B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]
B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]
B.11 Emergency Provisions [326 IAC 2-7-16]
B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]
B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]
B.14 Reserved
B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]
B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]
B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]
B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]
B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]
B.20 Source Modification Requirement [326 IAC 2-7-10.5]
B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]
B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]
B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]
B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

SECTION C SOURCE OPERATION CONDITIONS 25

Emission Limitations and Standards [326 IAC 2-7-5(1)] 25

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]
C.2 Opacity [326 IAC 5-1]
C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]
C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]
C.5 Fugitive Dust Emissions [326 IAC 6-4]
C.6 Reserved
C.7 Stack Height [326 IAC 1-7]
C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

Testing Requirements [326 IAC 2-7-6(1)] 27

C.9 Performance Testing [326 IAC 3-6]

Compliance Requirements [326 IAC 2-1.1-11] 27

C.10 Compliance Requirements [326 IAC 2-1.1-11]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 27
C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]
C.12 Reserved
C.13 Reserved
C.14 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6] 29
C.15 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]
C.16 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]
C.17 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]
C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 31
C.19 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]
C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]
C.21 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [40 CFR 64][326 IAC 3-8]

Stratospheric Ozone Protection 33
C.22 Compliance with 40 CFR 82 and 326 IAC 22-1

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS 34

Emission Limitations and Standards [326 IAC 2-7-5(1)] 34
D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

Compliance Determination Requirements 34
D.0.2 Compliance Determination for Combined Total HAP
D.0.3 Compliance Determination for Combined Formaldehyde
D.0.4 Testing Requirements [326 IAC 2-1.1-11]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 36
D.0.5 Record Keeping Requirement
D.0.6 Reporting Requirements

SECTION D.1 RESERVED 37

SECTION D.2 RESERVED 38

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS 39

Emission Limitations and Standards [326 IAC 2-7-5(1)] 39
D.3.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3][326 IAC 6-2-1(g)][326 IAC 7-1.1-2]
D.3.2 Reserved
D.3.3 Alternative Fuel Blends [326 IAC 2-2]
D.3.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)] 40
D.3.5 Reserved
D.3.6 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]
D.3.7 Operation of Electrostatic Precipitator
D.3.8 Scrubber Operation
D.3.9 Reserved
D.3.10 Continuous Emissions Monitoring [326 IAC 2-2] [326 IAC 3-5] [326 IAC 7-2-1(g)][326 IAC 12]

D.3.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
D.3.12 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 42
D.3.13 PM Monitoring System Downtime
D.3.14 SO_2 Monitoring System Downtime

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19] 43
D.3.15 Record Keeping Requirements
D.3.16 Reporting Requirements

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS 45

Emission Limitations and Standards [326 IAC 2-7-5(1)] 45
D.4.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]
D.4.2 Reserved
D.4.3 Reserved
D.4.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)] 45
D.4.5 NOx Control
D.4.6 Continuous Emissions Monitoring [326 IAC 3-5]
D.4.7 Reserved

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 46
D.4.8 Record Keeping Requirements
D.4.9 Reporting Requirements

SECTION D.5 RESERVED 47

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS 48

Emission Limitations and Standards [326 IAC 2-7-5(1)] 48
D.6.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]
D.6.2 Reserved
D.6.3 Particulate Emission Limitation for Manufacturing Processes [326 IAC 6-3-2]

Compliance Determination Requirements [326 IAC 2-7-5(1)] 49
D.6.4 Particulate Control
D.6.5 Reserved

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 50
D.6.6 Visible Emissions Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 50
D.6.7 Record Keeping Requirements

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS 51

Emission Limitations and Standards [326 IAC 2-7-5(1)] 52
D.7.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS 53

Emission Limitations and Standards [326 IAC 2-7-5(1)] 53
D.8.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]
D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 54
D.8.3 Visible Emissions Notations
D.8.4 Broken or Failed Bag Detection

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 54
D.8.5 Record Keeping Requirements

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS 56

Emission Limitations and Standards [326 IAC 2-7-5(1)] 56
D.9.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2-3]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 56
D.9.2 Visible Emissions Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 57
D.9.3 Record Keeping Requirements

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS 58

Emission Limitations and Standards [326 IAC 2-7-5(1)] 58
D.10.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS 59

Emission Limitations and Standards [326 IAC 2-7-5(1)] 59
D.11.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]
D.11.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 60
D.11.3 Record Keeping Requirements

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS 61

Emission Limitations and Standards [326 IAC 2-7-5(1)] 61
D.12.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS 62

Emission Limitations and Standards [326 IAC 2-7-5(1)] 62
D.13.1 PSD Minor Limit for PM and VOC [326 IAC 2-2]
D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

Compliance Determination Requirements [326 IAC 2-7-5(1)] 63
D.13.3 Testing Requirements [326 IAC 2-1.1-11]
D.13.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]
D.13.5 Compliance determination for PM and VOC

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 64
D.13.6 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 64
D.13.7 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]
D.13.8 Record Keeping Requirements
D.13.9 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]
D.13.10 Reporting Requirements

Acid Rain Program 67
E.1.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21][40 CFR 72 through 40 CFR 78]
E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

SECTION E.2 RESERVED 69

SECTION E.3 NSPS 70

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 70
E.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.3.2 Standards of Performance for Electric Utility Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Da]

SECTION E.4 NSPS 72

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 72
E.4.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.4.2 New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart Y]

SECTION E.5 NSPS 74

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 74
E.5.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.5.2 New Source Performance Standards for Stationary Gas Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart GG]

SECTION E.6 NSPS 75

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 75
E.6.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

SECTION E.7 RESERVED 77

SECTION E.8 NESHAP 78

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)] 78
E.8.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]
E.8.2 Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU] [326 IAC 20-89]

SECTION E.9 NESHAP 80

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)] 80
E.9.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]
E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-89]

SECTION E.10 NSPS 82

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 82
E.10.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.10.2 New Source Performance Standards for Stationary Combustion Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

SECTION E.11 NSPS 84

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 84
E.11.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

SECTION F EMISSIONS UNIT OPERATION CONDITIONS 86

Provisions of Northern Indiana Public Service Company LLC Consent Decree Applicable to R.M. Schahfer Generating Station 86

F.1 Consent Decree [*United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011), paragraph 169] [326 IAC 2-7-6(3)]

SECTION G RESERVED 87

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606) 88

ORIS Code: 994 88

H.1 Designated representative requirements
H.2 Emissions monitoring, reporting, and recordkeeping requirements
H.3 NOX annual emissions requirements
H.4 NOx ozone season requirements
H.5 SO_2 emissions requirements
H.6 Title V Permit Revision Requirements
H.7 Additional recordkeeping and reporting requirements
H.8 Liability
H.9 Effect on other authorities
H.10 Description of TR Monitoring Provisions

CERTIFICATION 102

EMERGENCY OCCURRENCE REPORT 103

Part 70 Quarterly Report 105

Part 70 Quarterly Report 106

Part 70 Quarterly Report 107

Part 70 Quarterly Report 108

Part 70 Quarterly Report 109

Part 70 Quarterly Report 110

QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT 111

Attachment A - Decree Paragraphs and Tables
Attachment B - Northern Indiana Public Service Company LLC - Consent Decree
Attachment C - Standards of Performance for Electric Utility Steam Generating Units [40 CFR Part 60, Subpart Da]
Attachment D - New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements [40 CFR Part 60, Subpart Y]
Attachment E - New Source Performance Standards for Stationary Gas Turbines Requirements [40 CFR Part 60, Subpart GG]
Attachment F - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII]
Attachment G - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR 63, Subpart UUUUU]
Attachment H - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR 63, Subpart ZZZZ]
Attachment I - New Source Performance Standards for Stationary Combustion Turbines Requirements [40 CFR Part 60, Subpart KKKK]

Attachment J - New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements [40 CFR Part 60, Subpart TTTTa]

SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

Source Address:	2723 East 1500 North, Wheatfield, Indiana 46392
General Source Phone Number:	219-956-5385
SIC Code:	4911
County Location:	Jasper
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

This stationary source consists of the following emission units and pollution control devices:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]

[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(f) Fuel storage and handling systems for Unit 17 and 18 boilers, constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

(g) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, constructed in 1980, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour, constructed in 1980.

(2) Three (3) ground limestone pneumatic truck unloading systems connected to Unit 17 and Unit 18 limestone silos, constructed in 1980, with baghouses for PM control.

(3) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour, constructed in 1980. All gypsum is handled wet.

(4) One (1) radial stacker, identified as 7MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2013.

(5) One (1) radial stacker, identified as 8MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2016.

(h) Dry fly ash handling and disposal.

(1) Pneumatic fly ash conveyance to storage silos, with a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 17, and 18, with cyclone separators, filter/separators**,** silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute, with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads and onsite disposal area.

(i) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(j) Ponded bottom ash handling/removal operations.

(k) Material handling for the flue gas desulfurization systems for Unit 17 and Unit 18 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Three (3) storage silos originally used for dual-alkali FGD system with baghouses for PM control.

(3) Two (2) upgraded incline belt conveyors, constructed in 2013, and shared among Units 17 and 18 for transfer of dewatered gypsum to the radial stackers.

(4) Transportation of off-specification gypsum by truck on unpaved roads.

(l) One (1) natural gas-fired temporary boiler, constructed in 2020, with a maximum capacity of less than or equal to 99.9 MMBtu per hour, using no control, and exhausting outdoors.

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]

This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) Conveyors as follows:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day.

(2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983.

(3) Uncovered coal conveying of less than or equal to 120 tons per day; and

(4) Underground conveyors.

(b) Coal bunker and coal scale exhausts and associated dust collector vents.

(c) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(d) Any of the following structural steel and bridge fabrication activities:

(1) Cutting 200,000 linear feet or less of one inch (1") plate or equivalent.

(2) Using 80 tons or less of welding consumables.

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(f) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations.

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(1) Coal pile wind erosion.

(2) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill.

(3) Shot blasters.

(4) Gypsum stockpiles.

(5) Cold Cleaner degreasing operations

(6) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

(h) Two (2) on-site storage piles, each with approximate storage area of 3,440 square feet.

(i) Truck transport of gypsum to the stockpiles and conveyor on paved and unpaved roads.

A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3).

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

(a) Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

(b) Notwithstanding B.1(a), the terms located in paragraphs of the Decree that are incorporated by reference into this permit in accordance with Section F and Attachment A shall have the definition, and only the definition, assigned to such terms in the Decree and are limited to Section F and Attachment A.

B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]

(a) This permit, T 073-45762-00008, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

B.3 Term of Conditions [326 IAC 2-1.1-9.5]

Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

B.5 Severability [326 IAC 2-7-5(5)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

This permit does not convey any property rights of any sort or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(35).

B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and

(5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

The Permittee shall implement the PMPs.

(b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee’s control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM,

OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency.

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

(2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

(4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T 073-45762-00008 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised under 326 IAC 2-7-10.5, or

(3) deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

B.14 Reserved

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that

meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source’s failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(c) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

(a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1) and (c)(1).

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;

(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Emission Trades [326 IAC 2-7-20(c)]
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ or U.S. EPA is required.

(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

(f) This condition does not apply to emission trades of SO_2 or NO_X under 326 IAC 21.

B.20 Source Modification Requirement [326 IAC 2-7-10.5]

A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-8590 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards [326 IAC 2-7-5(1)]

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

C.2 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

C.5 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.6 Reserved

C.7 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at

least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:

(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or

(2) If there is a change in the following:

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(c).

(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(d).

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(e) Procedures for Asbestos Emission Control
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).

(g) Indiana Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to

thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

Testing Requirements [326 IAC 2-7-6(1)]

C.9 Performance Testing [326 IAC 3-6]

(a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. In the event that a previously scheduled test must be canceled and rescheduled, the Permittee of the source or emissions unit shall notify the department no less than fourteen (14) days in advance of the rescheduled test date. Tests rescheduled for less than fourteen (14) days after notifying the department of the rescheduled test date must be approved by the department. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

C.10 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]

(a) For new units:
Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.

(b) For existing units:
Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance to begin such monitoring. If, due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

(c) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(d) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

C.12 Reserved

C.13 Reserved

C.14 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6]

C.15 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.16 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]

If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.17 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]

(I) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:

(a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to normal or usual manner of operation.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;

(2) review of operation and maintenance procedures and records; and/or

(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall record the reasonable response steps taken.

(II)

(a) CAM *Response to excursions or exceedances.*

(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a Quality Improvement Plan (QIP). The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8(b)(2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or

(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*

(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(c) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

C.19 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(33) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:

(AA) All calibration and maintenance records.
(BB) All original strip chart recordings for continuous monitoring instrumentation.
(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.
(BB) The dates analyses were performed.
(CC) The company or entity that performed the analyses.
(DD) The analytical techniques or methods used.
(EE) The results of such analyses.
(FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

C.21 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a

"responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C - Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(b) The address for report submittal is:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

Stratospheric Ozone Protection

C.22 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with applicable standards for recycling and emissions reduction.

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

Pursuant to SSM No. 073-47965-00008 and in order to render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA), prior to the startup, as defined at 40 CFR 63.2, of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20, and the emergency generator EDG1 and emergency fire pump FP1, the Permittee shall comply with following:

(a) The combined total HAPs emissions from the combustion turbines (16A, 16B, 19A, 19B, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined formaldehyde emissions from the combustion turbines (16A, 16B, 19A, 19B, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) Upon the commencement of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20, the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from the source.

(d) The limits in paragraphs (a) and (b) will be effective after the permanent shutdown and decommissioning of the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18 and the start of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20.

Compliance with these limits, combined with the potential to emit HAP from all other emission units at the source, shall limit the source-wide potential to emit single HAP to less than 10 tons per twelve (12) consecutive month period and the source-wide potential to emit total HAPs to less than 25 tons per twelve (12) consecutive month period, and shall render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA).

Compliance Determination Requirements

D.0.2 Compliance Determination for Combined Total HAP

In order to determine compliance with Condition D.0.1(a), the combined total HAP emissions from the entire source shall be determined using the following equation:

$$E_{THAP} = \sum_{i=1}^{12}\left(\sum_{n}\frac{\begin{array}{c}EF_{n19} * HI_{19A} + EF_{n19} * HI_{19B} + EF_{n19} * HI_{19C} + EF_{nU20} * HI_{U20} + EF_{n16} * HI_{16A} + \\ EF_{n16} * HI_{16B} + EF_{nTB} * NT_{TB} + EF_{n350FP} * DT_{350FP} + EF_{nFP1} * DT_{FP1} + EF_{nEDG1} * DT_{EDG1}\end{array}}{2000}\right)$$

Where:

E_{THAP} = Combined total HAP emissions (tons/month)
HI_{19A} = Heat input from turbine Unit 19A (MMBtu/month)
HI_{19B} = Heat input from turbine Unit 19B (MMBtu/month)
HI_{19C} = Heat input from turbine Unit 19C (MMBtu/month)
HI_{U20} = Heat input from turbine Unit 20 (MMBtu/month)
HI_{16A} = Heat input from turbine Unit 16A (MMBtu/month)
HI_{16B} = Heat input from turbine Unit 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (gallons/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (gallons/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (gallons/month)
EF_{n19} = Emission factors (in lb/MMBtu) for every single HAP from Units 19A, 19B, and 19C
EF_{nU20} = Emission factors (in lb/MMBtu) for every single HAP from Unit 20
EF_{n16} = Emission factors (in lb/MMBtu) for every single HAP from Units 16A and 16B
EF_{nTB} = Emission factors (in lb/MMscf) for every single HAP from temporary boiler
EF_{n350FP} = Emission factors (in lb/gallon) for every single HAP from 350 HP diesel fire pump
EF_{nEDG1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency generator EDG1
EF_{nFP1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency fire pump FP1
i = Each calendar month within the twelve (12) consecutive month period
n = Every single HAP emitted by emission units included in the HAP limit

D.0.3 Compliance Determination for Combined Formaldehyde

In order to determine compliance with Condition D.0.1(b), the combined single HAP (formaldehyde) emissions from the entire source shall be determined using the following equation:

$$\sum_{i=1}^{12} E_{Single\ HAP\ (Formaledyde)} = \frac{ER_{19} * HR_{19A} + ER_{19} * HR_{19B} + ER_{19} * HR_{19C} + ER_{U20} * HR_{U20} + EF_{16} * HI_{16A} + EF_{16} * HI_{16B} + EF_{TB} * NT_{TB} + EF_{350FP} * DT_{350FP} + EF_{FP1} * DT_{FP1} + EF_{EDG1} * DT_{EDG1}}{2000}$$

Where:

$E_{Single\ HAP\ (Formaldehyde)}$ = Single HAP (Formaldehyde) Emissions (tons/month)
ER_{19} = 0.920 lb/hr, emission rate for formaldehyde for turbines 19A, 19B, and 19C or value established in latest compliant stack test
ER_{U20} = 1.10 lb/hr, emission rate for formaldehyde for turbine Unit 20 or value established in latest compliant stack test
HR_{19A} = Number of operating hours per month for turbine 19A
HR_{19B} = Number of operating hours per month for turbine 19B
HR_{19C} = Number of operating hours per month for turbine 19C
HR_{U20} = Number of operating hours per month for turbine Unit 20
HI_{16A} = Heat input from turbine 16A (MMBtu/month)
HI_{16B} = Heat input from turbine 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (hp-hr/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (hp-hr/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (hp-hr/month)
EF_{16} = 7.10E-04 lb/MMBtu, formaldehyde emission factor from AP-42 (Chapter 3.1 - Table 3.1-3)
EF_{TB} = 7.50E-02 lb/MMscf, formaldehyde emission factor from AP-42 (Chapter 1.4 - Table 1.4-3)
EF_{350FP} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*

EF_{EDG1} = 5.52E-07 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.4 - Table 3.4-3)*
EF_{FP1} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*
i = Each calendar month within the twelve (12) consecutive month period
* Emission Factors in lb/hp-hr were calculated as follows: EF (lb/MMBtu) x 7,000 (Btu/hp-hr) x (1 MMBtu / 1,000,000 Btu)

D.0.4 Testing Requirements [326 IAC 2-1.1-11]

In order to demonstrate compliance with Condition D.0.1 and to verify the emission rates for formaldehyde, not later than 180 days after the startup of the following emission units, the Permittee shall perform formaldehyde testing as follows:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	Formaldehyde (0.920 lb/hr)	One time
Frame type combustion turbine	Unit 20	Formaldehyde (1.10 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.0.5 Record Keeping Requirement

(a) To document the compliance status with Conditions D.0.1, the Permittee shall maintain monthly records in accordance with (1) and (3) below. Records maintained for (1) and (3) shall be taken as stated below and shall be complete and sufficient to establish compliance with the combined HAPs and single HAP emission limits established in Conditions D.0.1:

(1) Monthly combined total HAP emissions as calculated using the equation in Condition D.0.2.

(2) Monthly combined single HAP (formaldehyde) emissions as calculated using the equation in Condition D.0.3.

(3) The dates of shutdown for each unit listed in Condition D.0.1(c).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.0.6 Reporting Requirements

A quarterly summary of the information to document the compliance status with D.0.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1(35).

SECTION D.1 RESERVED

SECTION D.2 RESERVED

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.3.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3][326 IAC 6-2-1(g)][326 IAC 7-1.1-2]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1460, issued on April 14, 1980:

(a) Each boiler unit (Units 17 and 18) shall not be operated in excess of 3,967 MMBtu per hour heat input. (in EPA-5-A-80-18 only)

(b) Stack gas particulate emissions shall be controlled to 0.03 pound or less of total suspended particulates per million BTU (lb/MMBtu) of heat input.

This requirement will be met by using electrostatic precipitators (ESP) which will provide a 99.8 percent guaranteed control efficiency. (in PC (37) 1460 only)

(c) The opacity of the exhaust gases shall not exceed twenty percent (20%) based on a six-minute average except for one six-minute period per hour of opacity not exceeding twenty-seven percent (27%). (EPA 5-A-80-18 only)

(d) Reserved.

(e) Nitrogen oxide emissions from each boiler shall not exceed 0.6 pound per million BTU (lb/MMBTU) of heat input.

(f) Reserved.

D.3.2 Reserved

D.3.3 Alternative Fuel Blends [326 IAC 2-2]

(a) Pursuant to a letter from IDEM, OAQ, to Northern Indiana Public Service Company LLC dated June 13, 1996, based on the results of emissions testing performed in 1995 and subsequent ambient air modeling studies, petroleum coke may be combusted in Units 17 and 18 at a blend rate of no more than 30 percent (30%) petroleum coke (by weight). The conditions of the Units 17 and 18 federal PSD construction permit are not affected by this ruling, and all requirements contained therein still apply.

(b) The flue gas desulfurization (FGD) system shall be in operation at all times when pet coke is being fired. Should an emergency condition occur which causes a malfunction of the FGD system, the Permittee shall cease bunkering pet coke until the FGD system is fully operational.

D.3.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.3.5 Reserved

D.3.6 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A) (iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment as specified in Section D.3.

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60, 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a continuous emission monitors other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

(1) If the CEM is required for monitoring NOx or SO2 emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 (SO2 and NOx Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.

(2) If the CEM is not used to monitor NOx or SO2 emissions pursuant to 40 CFR 75 or 326 IAC 24 (SO2 and NOx Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, or 40 CFR 75.

D.3.7 Operation of Electrostatic Precipitator

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator (ESP) shall be operated at all times that the corresponding boilers are in operation.

D.3.8 Scrubber Operation

Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with all applicable SO_2 emission limits.

D.3.9 Reserved

D.3.10 Continuous Emissions Monitoring [326 IAC 2-2] [326 IAC 3-5] [326 IAC 7-2-1(g)][326 IAC 12]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued on April 14, 1980, and 326 IAC 2-2, continuous emission monitoring systems for Units 17 and 18 shall be calibrated, maintained, and operated for measuring opacity, SO_2, NO_X, and either CO_2 or O_2, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 326 IAC 10-4, 40 CFR 60, or 40 CFR 75.

D.3.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

Compliance with the PM limitation in Condition D.3.1(b) shall be determined by use of a CEMS measuring PM emissions in accordance with the procedures in 40 CFR 63 Subpart UUUUU and this Condition. The Permittee shall certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 17 and Unit 18 to the atmosphere and record the output of the system as specified in paragraphs (a) through (e):

(a) The PM CEMS shall be certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).

(b) Compliance with the applicable particulate emission limitations in Condition D.3.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.

(c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.3.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO2) values that are below 5%.

(d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3.

D.3.12 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3]

The Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the limits as established in PSD Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Construction Permit PC (37) 1460, issued on April 14, 1980, using a thirty (30) day rolling arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or emergency conditions for SO_2. Compliance with the percentage reduction requirements for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.3.13 PM Monitoring System Downtime

(a) Whenever the PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used to provide information related to particulate emissions:

(1) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 17 or Unit 18 is in operation by measuring and recording the following:

(A) the primary and secondary currents of the T-R sets.

(B) the primary and secondary voltages of the T-R sets

(C) daily number of TR sets in service

D.3.14 SO_2 Monitoring System Downtime

Whenever both the primary and back up SO2 continuous emission monitoring systems (CEMS) are malfunctioning or down for repairs or adjustments for a period of twenty-four (24) hours or more, the Permittee shall monitor and record boiler load, recirculation pH, slurry valve position, and absorber level to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load, and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a back-up CEMs is brought online, the following shall be used to provide information related to SO2 emissions:

(a) If the CEMS is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(b) If the CEMS is down for twenty-four (24) hours or more:

(1) Either fuel sampling and fuel preparation and analysis shall be conducted in accordance with 326 IAC 3-7-2(b) and (c), 326 IAC 3-7-2(d) and 326 IAC 3-7-2(e) or, alternatively, a portable analyzer, properly calibrated according to manufacturer specifications (such as manufacturer operating or maintenance manuals), shall be used to monitor SO_2 emissions. To the extent the Permittee elects to conduct fuel sampling: the Permittee shall collect the coal sample as bunkered; coal shall be sampled at least three (3) times per day and at least one (1) time per eight (8) hour period unless no coal is bunkered during the preceding eight (8) hour period; and minimum sample size shall be five hundred (500) grams.

or

(2) Pursuant to 326 IAC 3-7-3, other manual and other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

(c) To the extent the Permittee elects to conduct fuel sampling to comply with Condition D.3.12, pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of any information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4 under this Condition D.3.12. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.3.15 Record Keeping Requirements

(a) To document the compliance status with requirements in Conditions D.3.1(b) the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the limits established in Condition D.3.1(b).

(1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(2) All ESP Parametric monitoring readings when used as backup for the duration when PM CEMS are down.

(b) The Permittee shall maintain all PM continuous emissions monitoring data, with calendar dates and beginning and ending times of any CEM downtime, the reasons for each CEM downtime, and the efforts made to correct the problem.

(c) To document the compliance status with SO_2 Conditions D.3.1, D.3.8, D.3.10, and D.3.12, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limit(s) as required in Conditions D.3.1, D.3.8, D.3.10, and D.3.12. The Permittee shall maintain records in accordance with (2) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g).

(2) All scrubber parametric monitoring readings taken during any periods of CEM downtime, in accordance with Condition D.3.12.

(d) To document the compliance status with NO_X Conditions D.3.1(e) and D.3.10, the Permittee shall maintain records of all NO_X and CO_2 or O_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6 and 326 IAC 2-2. Records shall be complete and sufficient to establish compliance with the NO_X limits as required in Conditions D.3.1(e) and D.3.10.

(e) Reserved.

(f) To document the compliance status with Condition D.3.3, the Permittee shall maintain records of the amount of petroleum coke combusted and the pet coke/coal blend rate for each boiler. Records shall be complete and sufficient to establish compliance with the fuel limit of Condition D.3.3 using a thirty (30) day rolling weighted average.

(g) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.3.16 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7, a quarterly report of PM, SO2, and NOx exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(b) Reserved

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.4.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-79-A-25, issued on August 16, 1979, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1380, issued on May 9, 1979:

(a) Nitrogen oxide (NO_X) emissions from each turbine shall not exceed 93 ppm at 15% oxygen on a dry basis.

(b) Each turbine unit shall not operate in excess of 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

D.4.2 Reserved

D.4.3 Reserved

D.4.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.4.5 NOx Control

To the extent necessary to comply with Condition D.4.1, the water injection systems which are used to control the NOx emissions from turbines 16A and 16B shall be in operation and control emissions from turbines 16A and 16B.

D.4.6 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 326 IAC 2-2 (PSD), the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring NOx and O_2 emissions rates from the combustion turbine stacks in accordance with 326 IAC 3-5 to demonstrate compliance with Condition D.4.1(a).

(b) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, or 40 CFR 75.

D.4.7 Reserved

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.4.8 Record Keeping Requirements

(a) To document the compliance status with Conditions D.4.1(a) and D.4.5, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the nitrogen oxides (NO_X) limits established in Conditions D.4.1(a).

(1) Data and results from the most recent stack test.

(2) To document the compliance status with Condition D.4.5, the Permittee shall maintain records of:

(i) All continuous monitoring system data of fuel consumption and the ratio of water to fuel being fired; or

(i) All continuous emission monitoring system (CEMS) data of NO_x and O_2 whenever Permittee elects to use CEMS to monitor NO_x and O_2.

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall maintain records of the date and times for all periods of turbine operation.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.4.9 Reporting Requirements

(a) To document the compliance status with Condition D.4.1(a), the Permittee shall submit a quarterly summary of:

(1) The ratio of water to fuel if using the continuous monitoring method outlined in 40 CFR 60, Subpart GG; or

(2) The NO_x emissions if using the continuous emissions monitoring method outlined in Condition D.4.5.

The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(35).

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall submit a quarterly summary of the hours of operation for each combustion turbine. These reports shall be submitted to the address listed in Section C - General Reporting Requirements, of this approval. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.5 RESERVED

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Fuel storage and handling systems for Unit 17 and 18 boilers constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:

(a) Conveyors as follows:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;

(3) Uncovered coal conveying of less than or equal to 120 tons per day.

(4) Underground conveyors.

(b) Coal bunker and coal scale exhausts and associated dust collector vents.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.6.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

(a) Particulate emissions from coal unloading shall not exceed ten percent (10%) opacity for the duration of the unloading operation.

(b) All coal conveyors shall be completely enclosed.

(c) All transfer points shall be completely enclosed except those at the storage pile.

(d) Particulate emissions from the crusher house, conveyor room and reclaim tunnels shall be controlled to 99 percent.

(e) Fugitive emissions from the coal piles shall be minimized by compaction and other appropriate measures (surfactant spray etc.).

D.6.2 Reserved

D.6.3 Particulate Emission Limitation for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), for the fuel storage and handling systems for Units 17 and 18 other than the coal storage piles, allowable particulate emissions for the coal handling operations shall be calculated as follows:

(a) Particulate shall not be emitted in excess of the amount shown in the table in 326 IAC 6-3-2(e). The allowable rate of emission shall be based on the process weight rate for the process.

(b) Interpolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$

where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

(c) Interpolation and extrapolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0\ P^{0.11} - 40$

where E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour.

(d) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emission may exceed that shown in the table in 326 IAC 6-3-2(e), provided the concentration of particulate in the discharge gases to the atmosphere is less than one-tenth (0.10) pound per one thousand (1,000) pounds of gases.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.6.4 Particulate Control

In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed bag will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed bag will be repaired or replaced. The notification shall also include the results of any

response actions taken up to the time of notification.

D.6.5 Reserved

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.6.6 Visible Emissions Notations

(a) Visible emission notations of the rail car unloading station openings shall be performed once per day during normal daylight operations when unloading coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the fuel transfer exhaust points shall be performed once per week during normal daylight operations when transferring fuel. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the coal crusher exhaust shall be performed once per week during normal daylight operations when the crusher is in operation. A trained employee shall record whether emissions are normal or abnormal.

(d) If abnormal emissions of dust are observed from the rail car unloading station openings, the fuel transfer exhaust points, or the coal crusher exhaust, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(e) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(f) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(g) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.6.7 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.6(a) - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the coal rail car unloading station openings. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.6.6(b) and (c) - Visible Emission Notations, the Permittee shall maintain weekly records of the visible emission notations of the coal transfer exhaust points and crusher baghouse exhaust. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, constructed 1980, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour, constructed in 1980.

(2) Three (3) ground limestone pneumatic truck unloading systems connected to Unit 17 and Unit 18 limestone silos, constructed in 1980, with baghouses for PM control.

(3) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour, constructed in 1980. All gypsum is handled wet.

(4) One (1) radial stacker, identified as 7MX04G-RS, shared among Unit 17 and 18, with rated capacity of 220 tons/hour, constructed in 2013.

(5) One (1) radial stacker, identified as 8MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2016.

(i) Material handling for the flue gas desulfurization systems for Unit 17and Unit 18 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Three (3) storage silos originally used for dual-alkali FGD system with baghouses for PM control.

(3) Two (2) upgraded incline belt conveyors constructed in 2013 and shared among Units 17 and 18 for transfer of dewatered gypsum to the radial stackers.

(4) Transportation of off-specification gypsum by truck on unpaved roads.

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:

(a) Conveyors as follows:

(2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983.

(4) Underground conveyors.

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(4) Gypsum stockpiles.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.7.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the limestone handling systems and gypsum transfer systems shall not exceed 30 pounds per hour, each, when operating at a process weight rate of 38,941 pounds per hour. This pounds per hour limitation was calculated using the following equation:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10 P^{0.67}$

Where:

E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

(b) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the two (2) radial stackers, identified as 7MX04G-RS and 8MX04G-RS, shall not exceed 59.55 pounds per hour, each, when operating at a process weight rate of 220 tons per hour. This pounds per hour limitation was calculated using the following equation:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0 P^{0.11} - 40$

Where:

E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes) when the process weight rate exceeds 200 tons per hour, the allowable emission may exceed the calculated (E) pounds per hour rate, provided the concentration of particulate in discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1000) pounds of gases.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(f) Dry fly ash handling and disposal.

(1) Pneumatic fly ash conveyance to storage silos, with a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 17, and 18, with cyclone separators, filter/separators**,** silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads; and onsite disposal area.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.8.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

For the fly ash from Units 17 and 18, pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

Fly ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. Trucks utilized for dry or unconditioned ash disposal shall be covered. (in EPA-5-A-80-18 only)

D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the Pneumatic fly ash conveyance from each of Units 17 and 18 shall not exceed 46.8 pounds per hour when operating at a process weight rate of 63 tons per hour of fly ash from each of Units 17 and 18. These pounds per hour limitations were calculated using the following equation:

Interpolation and extrapolation of the data for the process weight rate in excess of 60,000 pounds per hour shall be accomplished by use of the equation:

$E = 55.0\ P^{0.11} - 40$

Where:
E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for dry fly ash silo unloading at a throughput rate greater than 200 tons per hour, the concentration of particulate in the discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1,000) pounds of gases.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.8.3 Visible Emissions Notations

(a) Visible emission notations of the ash silo unloading station openings shall be performed at least once per day during normal daylight operations when ash is being unloaded. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the fly ash conveyance and silo bag filter and bin vent filter exhausts shall be performed at least once per day during normal daylight operations when transferring ash to the corresponding silo. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the nozzle of each telescoping chute shall be performed at least once per day during normal daylight operations when unloading ash through the chute. A trained employee shall record whether emissions are normal or abnormal.

(d) If abnormal visible emissions of ash are observed from the ash silo unloading station openings, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(e) If abnormal emissions are observed at any bag filter exhaust, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(f) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(g) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(h) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

D.8.4 Broken or Failed Bag Detection

In the event that bag failure has been observed:

For bin vent filters, if failure is indicated by an opacity violation, or if filter failure is determined by other means, such as gas temperatures, flow rates, air infiltration, leaks, dust traces or triboflows, then failed unit and the associated process will be shut down immediately until the failed unit has been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.8.5 Record Keeping Requirements

(a) To document the compliance status with Condition D.8.3 - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the Unit 17 and 18 ash silo unloading station openings, the Unit 17 and 18 baghouse stack exhaust, and nozzle of each telescoping chute. The Permittee shall include in its daily record when

a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g., the process did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(h) Ponded bottom ash handling/removal operations.

Insignificant Activities:

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(2) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.9.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2-3]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued on April 14, 1980, with respect to Units 17 and 18:

(a) The bottom ash shall be sluiced to waste disposal ponds. (in PC (37) 1460 only)

(b) Bottom ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. (in EPA-5-A-80-18 only)

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.9.2 Visible Emissions Notations

(a) Visible emission notations of any active onsite landfill area(s) shall be performed at least once per day during normal daylight operations. Any storage pond in the Waste Disposal Area or the Material Storage Runoff Pond area that contains either bottom ash and/or FGD sludge shall be observed once per week to determine if sufficient water is present in the pond to cover or saturate bottom ash and/or sludge deposited in the pond. During any period when there is not sufficient water in the pond to cover or saturate bottom ash and/or sludge present in the pond, visible emission notations of such storage pond area(s) shall be performed at least once per day during normal daylight operations. When daily visible emission notations are made, a trained employee shall record whether emissions are normal or abnormal.

(b) If visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(c) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(d) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(e) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.9.3 Record Keeping Requirements

(a) To document the compliance status with Condition D.9.2 - Visible Emission Notations, the Permittee shall maintain records of visible observations, and any resulting visible emission notations of the Waste Disposal Area and the Material Storage Runoff Pond area, and records of visible emission notations relating to any active onsite landfill area(s).The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Insignificant Activities:

(c) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(d) Any of the following structural steel and bridge fabrication activities:

(1) Cutting 200,000 linear feet or less of one inch (1") plate or equivalent.

(2) Using 80 tons or less of welding consumables.

(f) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations.

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(3) Shot blasters.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.10.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emission rate from the brazing, cutting, soldering, welding, grinding, and machining operations shall not exceed an amount determined by the following, for a process weight rate equal to or greater than 100 pounds per hour:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$

Where:

E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(5) Cold Cleaner degreasing operations

(6) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.11.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-1 and 8-3-2 (Cold Cleaner Degreaser Control and Equipment Operating Requirements), the Permittee shall:

(a) Pursuant to 326 IAC 8-3-1(c)(1)(B) for equipment constructed after January 1, 1980, ensure the following control equipment and operating requirements are met:

(1) Equip the degreaser with a cover.

(2) Equip the degreaser with a device for draining cleaned parts.

(3) Close the degreaser cover whenever parts are not being handled in the degreaser.

(4) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases.

(5) Provide a permanent, conspicuous label that lists the operating requirements in subdivisions (3), (4), (6), and (7).

(6) Store waste solvent only in closed containers.

(7) Prohibit the disposal or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.

(b) Pursuant to 326 IAC 8-3-1(c)(2)(A)(ii) for equipment constructed after July 1, 1990, ensure the following additional control equipment and operating requirements are met:

(1) Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent used is insoluble in, and heavier than, water.
(C) A refrigerated chiller.
(D) Carbon adsorption.
(E) An alternative system of demonstrated equivalent or better control as those outlined in clauses (A) through (D) that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

(2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.

(3) If used, solvent spray:
(A) must be a solid, fluid stream; and
(B) shall be applied at a pressure that does not cause excessive splashing.

D.11.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, the Permittee shall not operate a cold cleaning degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.11.3 Record Keeping Requirements

To document the compliance status with Condition D.11.2, on and after January 1, 2015, the Permittee shall maintain the following records for each purchase of solvent used in the cold cleaner degreasing operations. These records shall be retained on-site or accessible electronically for the most recent three (3) year period and shall be reasonably accessible for an additional two (2) year period.

(a) The name and address of the solvent supplier.

(b) The date of purchase.

(c) The type of solvent purchased.

(d) The total volume of the solvent purchased.

(e) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(j) One (1) natural gas-fired temporary boiler, constructed in 2020, with a maximum capacity of less than or equal to 99.9 MMBtu per hour, using no control, and exhausting outdoors.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.12.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1(f) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate emissions from the temporary boiler shall be limited to 0.10 pound per MMBtu heat input.

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.13.1 PSD Minor Limit for PM and VOC [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 157-47442-00044, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits shall limit the potential to emit PM and VOC to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008.

D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), the Permittee shall minimize VOC emissions from the frame-type natural gas-fired combustion turbine, identified as Unit 20, using the Best Available Control Technology (BACT), which has been determined to be the following:

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.13.3 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for NOx and demonstrate compliance with VOC limitation under Condition D.13.2(b), not later than 180 days after the startup of the following emission units, the Permittee shall perform NOx and VOC testing on the following emission units:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	NOx (45.90 lb/hr)	One time
Frame type combustion turbine	Unit 20	NOx (139.80 lb/hr) VOC (6.50 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.13.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the natural gas-fired combustion turbines Units 19A, 19B, 19C, and 20, shall be calibrated, maintained, and operated for measuring NOx, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, Subpart KKKK.

D.13.5 Compliance determination for PM and VOC

(a) To determine the compliance status with Condition D.13.1(a), the following equation shall be used to determine combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20 using the equation shown below for each:

$$E_{PM} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{PM} = Total PM emissions (tons/month) form the combustion turbine Units 19A, 19B, 19C, 20

ER_N = 4.90 lb/hr PM emission rate in normal operation for Units 19A, 19B, and 19C or 11.6 lb/hour PM emission rate in normal operation for Unit 20, or value established in latest stack tests

$ER_{(SU/SD)}$ = 4.90 lb/event, PM emission rate in startup/shutdown events for Units 19A, 19B, and 19C or 11.60 lb/event, PM emission rate in startup/shutdown events for Unit 20

Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle

H = Number of hours of normal operation for the month for Units 19A, 19B, 19C,

and 20
i = Each calendar month within the twelve (12) consecutive month period
n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

(b) To determine the compliance status with Condition D.13.1(b), the following equation shall be used to determine the combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20:

$$E_{VOC} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{VOC} = Total VOC emissions (tons/month) from the combustion turbine Units 19A, 19B, 19C, 20
ER_N = 5.40 lb/hr, VOC emission rate in normal operation for Units 19A, 19B, and 19C, or 6.50 lb/hr VOC emission rate in normal operation for Unit 20, or value established in latest stack test.
$ER_{(SU/SD)}$ = 1.40 lb/event, VOC emission rate in startup/shutdown events for Units 19A, 19B, and 19C, or 101.00 lb/event, VOC emission rate in startup/shutdown events for Unit 20
Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle
H = Number of hours of normal operation for the month for Units 19A, 19B, 19C, and 20
i = Each calendar month within the twelve (12) consecutive month period
n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.13.6 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.13.7 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Permittee shall record the output of the continuous monitoring system (lb/hr) and shall

perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligation with regard to the records required by this condition.

D.13.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.13.1, the Permittee shall maintain monthly records in accordance with (1) and (2) below. Records maintained for (1) and (2) shall be taken as stated below and shall be complete and sufficient to establish compliance with the PM and VOC emission limits established in Condition D.13.1:

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.6(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13.6(b).

(b) The number of startup and shutdown events per month.

(c) The number of minutes for each startup event and each shutdown event.

(d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.13.9 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;

(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

D.13.10 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.13.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION E.1 TITLE IV CONDITIONS

ORIS Code: 6085

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NOX burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NOX burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Acid Rain Program

E.1.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21][40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78.

E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

SECTION E.2 RESERVED

SECTION E.3 NSPS

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Da.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.3.2 Standards of Performance for Electric Utility Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Da]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Da (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.40Da(a)
(2) 40 CFR 60.42Da(a)
(3) 40 CFR 60.43Da(a), (b), and (h)
(4) 40 CFR 60.44Da(a)
(5) 40 CFR 60.48Da(a), (b), (d), (e), (h), (p), and (s)
(6) 40 CFR 60.49Da(b)(1), (4), (c), (d), (e), (f)(1), (g), (h), (i), (j), (s), and (w)
(7) 40 CFR 60.50Da(a), (b)(1), (3), (c), (d), and (e)
(8) 40 CFR 60.51Da(a), (b), (c), (j), and (k)

SECTION E.4 NSPS

Emissions Unit Description:

(d) Fuel storage and handling systems for Unit 17 and 18 boilers constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.4.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Y.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.4.2 New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart Y]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Y (included as Attachment D to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.250(a)&(b)
(2) 40 CFR 60.254(a)
(3) 40 CFR 60.255(a)

SECTION E.5 NSPS

Emissions Unit Description:

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.5.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart GG.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.5.2 New Source Performance Standards for Stationary Gas Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart GG]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart GG (included as Attachment E to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.330
(2) 40 CFR 60.332(a)&(f)
(3) 40 CFR 60.333
(4) 40 CFR 60.334
(5) 40 CFR 60.335

SECTION E.6 NSPS

Emissions Unit Description:

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.6.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart IIII (included as Attachment F to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit listed above:

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

(1) 40 CFR 60.4200(a)(2)(ii)
(2) 40 CFR 60.4205(c)
(3) 40 CFR 60.4206

(4) 40 CFR 60.4207(a)
(5) 40 CFR 60.4207(b)
(6) 40 CFR 60.4209(a)
(7) 40 CFR 60.4211(a)
(8) 40 CFR 60.4211(c)
(9) 40 CFR 60.4211(f)
(10) 40 CFR 60.4211(g)(2)
(11) 40 CFR 60.4214(b)
(12) 40 CFR 60.4218
(13) Table 3 to Subpart IIII of Part 60
(14) Table 4 to Subpart IIII of Part 60
(15) Table 8 to Subpart IIII of Part 6

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 60.4200(a)
(2) 40 CFR 60.4205(b) and (c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4208
(6) 40 CFR 60.4209
(7) 40 CFR 60.4211(a), (c), and (f)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b) and (c)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 2 to Subpart IIII of Part 60
(13) Table 5 to Subpart IIII of Part 60
(14) Table 8 to Subpart IIII of Part 60

SECTION E.7 **RESERVED**

SECTION E.8 NESHAP

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.8.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart UUUUU.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.8.2 Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU] [326 IAC 20-89]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart UUUUU (included as Attachment G to the operating permit), which are incorporated by reference as 326 IAC 20-89, for the emission unit(s) listed above:

(1) 40 CFR 63.9980
(2) 40 CFR 63.9981
(3) 40 CFR 63.9982(a)(1) and (d)
(4) 40 CFR 63.9984(b), (c), and (f)
(5) 40 CFR 63.9990(a)(2) and (c)
(6) 40 CFR 63.9991(a)(1) and (b)
(7) 40 CFR 63.10000(a), (b), (c)(1), (d), (e), (f), (j), (k), and (l)
(8) 40 CFR 63.10005(a)(1), (a)(2), (b), (d)(1), (d)(3), (e), (j), and (k)
(9) 40 CFR 63.10006
(10) 40 CFR 63.10007(a)(1), (b), (e)(2), (f), and (g)
(11) 40 CFR 63.10009
(12) 40 CFR 63.10010(a)(1), (b), (d), (f), (g), and (i)
(13) 40 CFR 63.10011(a), (c), (e), (f), and (g)
(14) 40 CFR 63.10020(a), (b), (c), and (d)
(15) 40 CFR 63.10021(a), (b), (e), (f), (g), and (h)
(16) 40 CFR 63.10022
(17) 40 CFR 63.10030(a), (b), (d), and (e)
(18) 40 CFR 63.10031(a)(1), (a)(3), (a)(5), (b), (c)(1), (c)(2), (c)(3), (c)(4), (c)(8), (c)(9), (c)(10), (d), (e), (f), (g), and (j)
(19) 40 CFR 63.10032(a), (b), (c), (d)(1), (f)(1), (g), (h), and (i)
(20) 40 CFR 63.10033
(21) 40 CFR 63.10040
(22) 40 CFR 63.10041
(23) 40 CFR 63.10042
(24) Table 2 Item 2 to Subpart UUUUU of Part 63
(25) Table 3 Item 1, 3, and 4 to Subpart UUUUU of Part 63
(26) Table 5 Item 4 to Subpart UUUUU of Part 63
(27) Table 7 Item 4, 5, 6, and 7 to Subpart UUUUU of Part 63
(28) Table 8 to Subpart UUUUU of Part 63
(29) Table 9 to Subpart UUUUU of Part 63
(30) Appendix A to Subpart UUUUU of Part 63
(29) Appendix C to Subpart UUUUU of Part 63
(30) Appendix E to Subpart UUUUU of Part 63

SECTION E.9 NESHAP

Emissions Unit Description:

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.9.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart ZZZZ.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-89]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment H to the operating permit), which are incorporated by reference as 326 IAC 20-82, for the emission unit(s) listed above:

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585

(3) 40 CFR 63.6590(c)(7)
(4) 40 CFR 63.6595(a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(ii) and (c)(7)

SECTION E.10 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.10.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart KKKK.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.10.2 New Source Performance Standards for Stationary Combustion Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart KKKK (included as Attachment I to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.4305
(2) 40 CFR 60.4315
(3) 40 CFR 60.4320(a)
(4) 40 CFR 60.4330(a)
(5) 40 CFR 60.4333
(6) 40 CFR 60.4340
(7) 40 CFR 60.4345
(8) 40 CFR 60.4350
(9) 40 CFR 60.4355

(10) 40 CFR 60.4365
(11) 40 CFR 60.4370(b)
(12) 40 CFR 60.4375
(13) 40 CFR 60.4380
(14) 40 CFR 60.4395
(15) 40 CFR 60.4400
(16) 40 CFR 60.4405
(17) 40 CFR 60.4410
(18) 40 CFR 60.4420
(19) Table 1 to Subpart KKKK of Part 60

SECTION E.11 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.11.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart TTTTa.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart TTTTa (included as Attachment J to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.5509a(a)
(2) 40 CFR 60.5515a
(3) 40 CFR 60.5520a
(4) 40 CFR 60.5525a
(5) 40 CFR 60.5535a
(6) 40 CFR 60.5550a
(7) 40 CFR 60.5555a

(8) 40 CFR 60.5560a
(9) 40 CFR 60.5565a
(10) 40 CFR 60.5580a
(11) Table 1 to Subpart TTTTa of Part 60
(12) Table 3 to Subpart TTTTa of Part 60

SECTION F EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Provisions of Northern Indiana Public Service Company LLC Consent Decree Applicable to R.M. Schahfer Generating Station

F.1 Consent Decree [*United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011), paragraph 169] [326 IAC 2-7-6(3)]

This source is subject to certain conditions, requirements and limitations set forth in the consent decree entered into by and among the United States, the State of Indiana, and the Permittee in *United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011) (herein referred to as the "Decree"). Pursuant to paragraph 169 of the Decree, those paragraphs and tables of the Decree listed in Attachment A of this permit are incorporated by reference into this permit and are applicable requirements under this permit. Subject to the terms and conditions of this Section F.1, the Permittee shall comply with the paragraphs and tables of the Decree that are listed in Attachment A of this permit. A copy of the Decree is attached to this permit as Attachment B. However, only those specific paragraphs and tables of the Decree that are included in Attachment A of this permit and incorporated by reference pursuant to this Section F.1, are applicable requirements enforceable through this permit.

Each paragraph and table listed in Attachment A of this permit is incorporated by reference in its entirety, including any and all paragraphs, conditions, requirements and/or limitations of the Decree explicitly referenced in such paragraphs or tables. However, the Permittee's obligations under this permit to comply with the conditions, requirements and limitations incorporated by reference in the paragraphs and tables listed in Attachment A of this permit shall be limited to those conditions, requirements and limitations applicable to, and only to the extent applicable to, the R.M. Schahfer Station while this permit is in effect. For clarity, such applicable conditions, requirements and limitations shall, subject to the subsequent paragraph, include the annual system tonnage limitations applicable to the Northern Indiana Public Service Company LLC System (as that term is defined under paragraph 36 of the Decree) as a whole as provided under Table 4 and Table 6 of the Decree as listed in Attachment A hereto.

In accordance with paragraph 169 of the Decree, any noncompliance with an annual system tonnage limitation incorporated by reference pursuant to this Section F.1 and Attachment A shall constitute a single violation for the Northern Indiana Public Service Company LLC System (as that term is defined under paragraph 36 of the Decree) as a whole and does not create a separate violation or violations for each unit or source within the Northern Indiana Public Service Company LLC System. Compliance with the paragraphs and tables listed in Attachment A of this permit shall be determined exclusively by reference to the conditions, requirements, and limitations of the Decree. Whenever any conflict or inconsistency arises between the Decree and this permit, the terms and conditions of the Decree control.

SECTION G **RESERVED**

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)

ORIS Code: 994

Transport Rule (TR):

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NOX control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20,

approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

H.1 Designated representative requirements

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with the following:

(a) 40 CFR 97.413 through 97.418.
(b) 40 CFR 97.513 through 97.518; and
(c) 40 CFR 97.613 through 97.618.

H.2 Emissions monitoring, reporting, and recordkeeping requirements

(1) The owners and operators, and the designated representative, of each TR NO_X Annual source, TR NOx Ozone Season source, and TR SO2 Group 1 source, and each TR NO_X Annual unit at the source, TR NOx Ozone Season unit at the source, and TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.530, and 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.531, and 97.631 (initial monitoring system certification and recertification procedures), 97.432, 97.532, and 97.632 (monitoring system out-of-control periods), 97.433, 97.533, and 97.633 (notifications concerning monitoring), 97.434, 97.534, and 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.535, and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under Condition H.3 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(3) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under Condition H.4 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in

accordance with 40 CFR 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(4) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under Condition H.5 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

H.3 NOX annual emissions requirements

(1) TR NO_X Annual emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the TR NO_X Annual units at a TR NO_X Annual source are in excess of the TR NO_X Annual emissions limitation set forth in Condition H.3(1)(i) above, then:

(A). The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each TR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) TR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all TR NO_X Annual units at TR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to

the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NO_X Annual allowances required under Condition H.3(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Annual units at TR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NO_X Annual allowances for a control period in a given year in accordance with Condition H.3(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with Condition H.3(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A TR NO_X Annual unit shall be subject to the requirements under Condition H.3(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A TR NO_X Annual unit shall be subject to the requirements under Condition H.3(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NO_X Annual allowance held for compliance with the requirements under Condition H.3(1)(i) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NO_X Annual allowance held for compliance with the requirements under Condition H.3(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the TR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Annual allowance does not constitute a property right.

H.4 NOx ozone season requirements

(1) TR NO_X Ozone Season emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

(ii). If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source are in excess of the TR

NO_X Ozone Season emissions limitation set forth in Condition H.4(1)(i) above, then:

(A). The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under 40 CFR 97.524(d); and

(B). The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(2) TR NO_X Ozone Season assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.525(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NO_X Ozone Season allowances required under Condition H.4(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season trading budget under 40 CFR 97.510(a) and the state's variability limit under 40 CFR 97.510(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart BBBBB or of the Clean Air Act if total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NO_X Ozone Season allowances for a control period in a given year in accordance with Condition H.4(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NOX Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (d)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(3) Compliance Periods.

(i). A TR NOx Ozone Season unit shall be subject to the requirements under Condition H.4(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.530(b) and for each control period thereafter.

(ii). A TR NOx Ozone Season unit shall be subject to the requirements under Condition H.4(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NOx Ozone Season allowance held for compliance with the requirements under Condition H.4(1)(i) above for a control period in a given year must be a TR NOx Ozone Season Allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NOx Ozone Season allowance held for compliance with the requirements under Condition H.4(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a

control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowances Management System Requirements.

(i). Each TR NOx Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart BBBBB.

(6) Limited Authorization.

(i). A TR NOx Ozone Season allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(A). Such authorization shall only be used in accordance with the TR NOx Ozone Season Trading Program; and

(B). Notwithstanding any other provision of 40 CFR Part 97, Subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property Right.

(i). A TR NOx Ozone Season allowance does not constitute a property right.

H.5 SO_2 emissions requirements

(1) TR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 1 source and each TR SO2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source are in excess of the TR SO_2 Group 1 emissions limitation set forth in Condition H.5(1)(i) above, then:

(A). The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such

control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) TR SO_2 Group 1 assurance provisions

(i). If total SO_2 emissions during a control period in a given year from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR SO_2 Group 1 allowances required under Condition H.5(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR SO_2 Group 1 allowances for a control period in a given year in accordance with Condition H.5(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Condition H.5(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i) A TR SO_2 Group 1 unit shall be subject to the requirements under Condition H.5(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii) A TR SO_2 Group 1 unit shall be subject to the requirements under Condition H.5(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR SO_2 Group 1 allowance held for compliance with the requirements under Condition H.5(1)(i) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO_2 Group 1 allowance held for compliance with the requirements under Condition H.5(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the TR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO_2 Group 1 allowance does not constitute a property right.

H.6 Title V Permit Revision Requirements

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA, TR NO_X Ozone Season allowances in accordance with 40 CFR part 97, subpart BBBBB, and TR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.530 through 97.535, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.506(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

H.7 Additional recordkeeping and reporting requirements

(1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit, TR NO_X Ozone Season source and each TR NO_X Ozone Season unit, and TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 for the designated representative for the source and each TR NO_X Annual unit, TR NOx Ozone Season unit, and TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA, 40 CFR part 97, subpart BBBBB, and 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the

requirements of, the TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit, a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit, and a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.518, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

H.8 Liability

(1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(3) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season source or the designated representative of a TR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season units at the source.

(4) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season unit or the designated representative of a TR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(5) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(6) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

H.9 Effect on other authorities

No provision of the TR NO_X Annual Trading Program or exemption under 40 CFR 97.405, TR NO_X Ozone Season Trading Program or exemption under 40 CFR 97.505, and TR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit, TR NO_X Ozone Season source or TR NO_X Ozone Season unit, and TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

H.10 Description of TR Monitoring Provisions

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NOx Annual Trading Program and TR NOx Ozone Season Trading Program and TR SO2 Group 1 Trading Program.

Unit ID: Unit 17 and Unit 18					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X	-------	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	X	-------	-------	-------	-------

Unit ID: 16A and 16B					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	X	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	-------	X	-------	-------	-------

Unit ID: 19A, 16B, 19C, and Unit 20					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	X	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	-------	X	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify) _____

☐ Report (specify) _____

☐ Notification (specify) _____

☐ Affidavit (specify) _____

☐ Other (specify) _____

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
Signature:
Printed Name:
Title/Position:
Phone:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: (317) 233-0178
Fax: (317) 233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

This form consists of 2 pages **Page 1 of 2**

□ This is an emergency as defined in 326 IAC 2-7-1(12)
- The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile within two (**2**) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by: _____

Title / Position: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Turbine 16A
Parameter: Operating Hours
Limit: Less than 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	(Hrs.)	***(Hrs.)***	***(Hrs.)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Turbine 16B
Parameter: Operating Hours
Limit: Less than 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	(Hrs.)	***(Hrs.)***	***(Hrs.)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: PM Emissions
Limit: Shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	PM Emissions (tons)	***PM Emissions (tons)***	***PM Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: VOC Emissions
Limit: Shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	VOC Emissions (tons)	***VOC Emissions (tons)***	***VOC Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Source-wide
Parameter: Combined Total HAP Emissions
Limit: Shall be less than 25 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Total HAP Emissions (tons)	***Total HAP Emissions (tons)***	***Total HAP Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Source-wide
Parameter: Combined Single HAP (Formaldehyde) Emissions
Limit: Shall be less than 10 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Single HAP (Formaldehyde) Emissions (tons)	***Single HAP (Formaldehyde) Emissions (tons)***	***Single HAP (Formaldehyde) Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

Months: _____ to _____ Year: _____

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C-General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.

☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

Attachment F

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on September 5, 2024]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C, except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 86 FR 34357, June 29, 2021]

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 1039.102, 1039.104, 1039.105, 1039.107, and 1039.115 and 40 CFR part 1039, appendix I, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34357, June 29, 2021]

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The Tier 2 emission standards for new nonroad CI engines for the appropriate rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 for model year 2007 engines; and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section. Engines that would be subject to the Tier 4 standards in 40 CFR part 1042 that are used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section may instead continue to be certified to the previous tier of standards in 40 CFR part 1042. The previous tier is Tier 3 in most cases; however, the previous tier is Tier 2 if there are no Tier 3 standards specified for engines of a certain size or power rating.

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this

section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021; 88 FR 4471, Jan. 24, 2023]

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 86 FR 34358, June 29, 2021]

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) [Reserved]

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder must use diesel fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 85 FR 78463, Dec. 4, 2020]

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a

backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §§ 60.4201(a) through (c) and 60.4202(a), (b), and (d) using the certification procedures required in 40 CFR part 1039, subpart C, and must test their engines as specified in 40 CFR part 1039. For the purposes of this subpart, engines certified to the standards in Table 1 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I. For the purposes of this subpart, engines certified to the standards in Table 4 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §§ 60.4201(d) and (e) and 60.4202(e) and (f) using the certification procedures required in 40 CFR part 1042, subpart C, and must test their engines as specified in 40 CFR part 1042.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135 and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking, and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of § 60.4201 or § 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR part 1039, appendix I, when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in

sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

(k) Manufacturers of any size may certify their emergency stationary CI internal combustion engines under this section using assigned deterioration factors established by EPA, consistent with 40 CFR 1039.240 and 1042.240.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR part 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(a) or § 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified to emission standards for the same model year and maximum engine power as described in 40 CFR parts 1039 and 1042, as applicable. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the

owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain

and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021; 87 FR 48605, Aug. 10, 2022]

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or with Tier 2 emission standards as described in 40 CFR part 1042, appendix I, may follow the testing procedures specified in § 60.4213, as appropriate.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE subject to Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or Tier 2 emission standards as described in 40 CFR part 1042, appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR part 1039 or 1042, as applicable.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011; 86 FR 34359, June 29, 2021]

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\ O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section. Beginning on February 26, 2025, submit the notification electronically according to paragraph (g) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)-(vi) [Reserved]

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

(f) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test required under this section following the procedures specified in paragraphs (f)(1) and (2) of this section.

(1) ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.*** Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to paragraph (g) of this section. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to paragraph (g) of this section.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is

required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 87 FR 48606, Aug. 10, 2022; 89 FR 70512, Aug. 30, 2024]

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the Tier 2 or Tier 3 emission standards described in 40 CFR part 1042 for the same model year, displacement, and maximum engine power, as appropriate, rather than the otherwise applicable requirements of 40 CFR part 1039, as indicated in §§ 60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§ 60.4202 and 60.4205, and not those for non-emergency engines in §§ 60.4201 and 60.4204, except that for 2014 model year and later nonemergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards identified in appendix I of 40 CFR part 1039 or in 40 CFR 1042.101.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§ 60.4218 What General Provisions and confidential information provisions apply to me?

(a) Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

(b) The provisions of 40 CFR 1068.10 and 1068.11 apply for engine manufacturers. For others, the general confidential business information (CBI) provisions apply as described in 40 CFR part 2.

[88 FR 4471, Jan. 24, 2023]

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 1042.101(e).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34360, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	Emission standards for stationary fire pump engines in g/KW-hr (g/HP-hr)		
		NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
KW<8 (HP<11)	2011 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
8≤KW<19 (11≤HP<25)	2011 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	2011 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
37≤KW<56 (50≤HP<75)	2011 +[1]	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
56≤KW<75 (75≤HP<100)	2011 +[1]	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
75≤KW<130 (100≤HP<175)	2010 +[2]	4.0 (3.0)	5.0 (3.7)	0.30 (0.22)

130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
130≤KW<225 (175≤HP<300)	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
225≤KW<450 (300≤HP<600)	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)	2009 +	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
KW>560 (HP>750)	2008 +	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

[89 FR 70513, Aug. 30, 2024]

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Each	Complying with the requirement to	You must	Using	According to the following requirements
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Attachment H

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on September 5, 2024]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source:69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) ***Affected source.*** An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) ***Existing stationary RICE.***

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) ***New stationary RICE.***

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) ***Reconstructed stationary RICE.***

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) ***Stationary RICE subject to limited requirements.***

(1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) ***Stationary RICE subject to Regulations under 40 CFR Part 60.*** An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6595 When do I have to comply with this subpart?

(a) ***Affected sources.***

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) ***Area sources that become major sources.*** If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250

and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013; 89 FR 70515, Aug. 30, 2024]

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR

1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) [Reserved]

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013, as amended at 85 FR 78463, Dec. 4, 2020; 87 FR 48607, Aug. 10, 2022]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)

(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_O = \frac{0.209\ F_d}{F_C} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters,

kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

(j) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedure specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(5) Beginning on February 26, 2025, within 60 days after the date of completing each continuous emissions monitoring system (CEMS) performance evaluation (as defined in § 63.2) that includes a relative accuracy test audit (RATA), you must submit the results of the performance evaluation following the procedures specified in § 63.9(k). The results of performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. The results of performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be included as an attachment in the ERT or alternate electronic file.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of table 2c to this subpart or in items 1 or 4 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of table 2c to this subpart or in items 5, 6, 7, 8, 10, 11, or 13 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an initial notification not later than December 13, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in portable document format (PDF) consistent with § 63.9(k).

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an initial notification not later than July 16, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008, and you are required to submit an initial notification, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) Before February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2). Beginning on February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including a summary of the performance test results, in PDF to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), before the close of business on the 60th day following the completion of the performance test following the procedure specified in § 63.9(k), except any Confidential Business Information (CBI) is to be submitted according to paragraphs (h)(2)(i) and (ii) of this section. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file, including information claimed to be CBI, to the EPA following the procedures in paragraphs (h)(2)(i) and (ii) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as

CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(2).

(i) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in paragraph (h)(2) of this section, should include clear CBI markings and be flagged to the attention of the Reciprocating Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(ii) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711, Attention Reciprocating Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013; 85 FR 73912, Nov. 19, 2020; 89 FR 70516, Aug. 30, 2024]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (8) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the starting and ending date and time, the duration (in hours), and a brief description for each malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(7) Engine site rating in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

(8) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(9) An engine can be claimed as exempt from reporting coordinates (latitude/longitude) via CEDRI if:

(i) During the reporting period, the engine will be owned by, or operated by or for, an agency of the Federal Government responsible for national defense; and

(ii) The agency determines that disclosing the coordinates to the general public would be a threat to national security.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (8) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time (in hours) of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration (in hours), and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) A description of any changes in processes, or controls since the last reporting period.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (8) and (e)(1) through (13) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The start and end date and time and the duration (in hours) that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The start and end date and time and the duration (in hours) that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration (in hours) of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration (in hours) of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration (in hours) of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) [Reserved]

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(13) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any

emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. Beginning on February 26, 2025, the semiannual and annual compliance report required in table 7 of this subpart must be submitted according to paragraph (i) of this section. Only those elements required under this subpart are required to be submitted according to paragraph (i) of this section.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)-(vi) [Reserved]

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration (in hours), and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) Before February 26, 2025, the annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart

is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13. Beginning on February 26, 2025, the annual report must be submitted according to paragraph (i) of this section.

(i) Beginning on February 26, 2025 for the annual report specified in § 63.6650(h) and February 26, 2025 or one year after the report becomes available in CEDRI, whichever is later for all other semiannual or annual reports, submit all semiannual and annual subsequent compliance reports using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in § 63.9(k), except any CBI must be submitted according to the procedures in § 63.6645(h). The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70517, Aug. 30, 2024]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

(2) Records of the occurrence and duration (in hours) of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purpose specified in § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70518, Aug. 30, 2024]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

[69 FR 33506, June 15, 2004, as amended at 89 FR 70518, Aug. 30, 2024]

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013; 87 FR 48608, Aug. 10, 2022]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.		

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.	

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	

3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.		

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	**You must meet the following operating limitation, except during periods of startup . . .**
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	

existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.	

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first[2]. b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first[2].	
	b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[2]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	b. Inspect spark plugs every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[89 FR 70518, Aug. 30, 2024]

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1] b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	b. Inspect spark plugs every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[89 FR 70520, Aug. 30, 2024]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.
[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.		

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device; and	(2) ASTM D6522-00 (Reapproved 2005)[123] (heated probe not necessary) or method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.
		iv. Measure moisture content at the inlet and outlet of the control device as needed to determine CO and O_2 concentrations on a dry basis	(3) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(d) Measurements to determine moisture content must be made at the same time and location as the measurements for CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE	a. Reduce formaldehyde or THC emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, THC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device as needed to determine formaldehyde or THC and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[13] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(4) (1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(e) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location as needed to determine formaldehyde or CO and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[13] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(4) Method 10 of 40 CFR part 60, appendix A-4, ASTM D6522-00 (2005),[13] method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(e) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[1] You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).

[2] You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[3] Incorporated by reference, see § 63.14.

[88 FR 18413, Mar. 29, 2023]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.
[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.		

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)-(9) and (i) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in § 63.6650(b) and (i).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4)	i. Semiannually according to the requirements in § 63.6650(b) and (i).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters	i. See item 2.a.i.

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i).
4. Emergency stationary RICE that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. Annually according to the requirements in § 63.6650(h)(2)-(3) and (i).

[89 FR 70522, Aug. 30, 2024]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions	Yes	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes	
§ 63.4	Prohibited activities and circumvention	Yes	
§ 63.5	Construction and reconstruction	Yes	
§ 63.6(a)	Applicability	Yes	
§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes	
§ 63.6(b)(5)	Notification	Yes	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No	
§ 63.6(f)(1)	Applicability of standards	No	
§ 63.6(f)(2)	Methods for determining compliance	Yes	
§ 63.6(f)(3)	Finding of compliance	Yes	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes	
§ 63.6(j)	Presidential compliance exemption	Yes	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes	
§ 63.7(e)(1)	Conditions for conducting performance tests	No	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes	
§ 63.7(f)	Alternative test method provisions	Yes	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes	
§ 63.7(h)	Waiver of tests	Yes	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No	
§ 63.8(b)(1)	Monitoring	Yes	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
			Except that § 63.8(e) only applies as specified in § 63.6645.
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements	Yes	
§ 63.9(b)(1)-(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
			Except that § 63.9(b) only applies as specified in § 63.6645.
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use. Except that § 63.9(g) only applies as specified in § 63.6645.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes	
§ 63.9(j)	Change in previous information	Yes	
§ 63.9(k)	Electronic reporting procedures	Yes	Only as specified in §§ 63.9(j), 63.6620, 63.6625, 63.6645, and 63.6650.
§ 63.10(a)	Administrative provisions for recordkeeping/reporting	Yes	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes	
§ 63.10(b)(3)	Records of applicability determination	Yes	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes	
§ 63.10(d)(2)	Report of performance test results	Yes	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	No	Excess emissions and exceedance reporting is specified in § 63.6650.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes	
§ 63.11	Flares	No	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.12	State authority and delegations	Yes	
§ 63.13	Addresses	Yes	
§ 63.14	Incorporation by reference	Yes	
§ 63.15	Availability of information	Yes	

[89 FR 70522, Aug. 30, 2024]

Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or

modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 ***Measurement System.*** The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 ***Data Recorder.*** A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 ***Electrochemical (EC) Cell.*** A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 ***Interference Gas Scrubber.*** A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 ***Moisture Removal System.*** Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 ***Sample Interface.*** The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 ***Nominal Range.*** The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 ***Calibration Gas.*** A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 ***Zero Calibration Error.*** The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 ***Up-Scale Calibration Error.*** The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 ***Interference Check.*** A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 ***Repeatability Check.*** A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 ***Sample Flow Rate.*** The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 ***Sampling Run.*** A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 ***Sampling Day.*** A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 ***Pre-Sampling Calibration/Post-Sampling Calibration Check.*** The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 ***Performance-Established Configuration.*** The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 ***Sample Probe.*** A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 ***Sample Line.*** Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 ***Calibration Assembly (optional).*** A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 ***Particulate Filter (optional).*** Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 ***Sample Pump.*** A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 ***Sample Flow Rate Monitoring.*** An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 ***Sample Gas Manifold (optional).*** A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 ***EC cell.*** A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 ***Data Recorder.*** A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 ***Interference Gas Filter or Scrubber.*** A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 ***Calibration Gases.*** CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 ***Up-Scale CO Calibration Gas Concentration.*** Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 ***Up-Scale O_2 Calibration Gas Concentration.***

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 ***Zero Gas.*** Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 ***Selection of Sampling Sites.***

8.1.1 ***Control Device Inlet.*** Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 ***Exhaust Gas Outlet.*** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 ***Stack Gas Collection and Analysis.*** Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 ***EC Cell Rate.*** Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 ***Pre-Sampling Calibration.*** Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 ***Zero Calibration.*** For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 ***Zero Calibration Tolerance.*** For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 ***Up-Scale Calibration.*** Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 ***Up-Scale Calibration Error.*** The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 ***Post-Sampling Calibration Check.*** Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 ***Measurement Data Phase Performance Check.*** Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example:

A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 ***Interference Check.*** Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 ***Interference Response.*** The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 ***Repeatability Check.*** Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 ***Repeatability Check Procedure.*** Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 ***Repeatability Check Calculations.*** Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) ***"Development of an Electrochemical Cell Emission Analyzer Test Protocol"*** , Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) ***"Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers"*** , EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) ***"ICAC Test Protocol for Periodic Monitoring"*** , EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) ***"Code of Federal Regulations"*** , Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility_____ Engine I.D._____ Date_____

Run Type: (X)	(_) Pre-Sample Calibration		(_) Stack Gas Sample		(_) Post-Sample Cal. Check		(_) Repeatability Check				
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
"											
"											
"											
"											
Measurement Data Phase											
"											
"											
"											
"											
"											
"											
"											
"											
"											
Mean											
Refresh Phase											
"											
"											
"											
"											

[78 FR 6721, Jan. 30, 2013]

Attachment I

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on May 12, 2021]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

SOURCE: 71 FR 38497, July 6, 2006, unless otherwise noted.

INTRODUCTION

§60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

APPLICABILITY

§60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

EMISSION LIMITS

§60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§60.4330 What emission limits must I meet for sulfur dioxide (SO2?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

GENERAL COMPLIANCE REQUIREMENTS

§60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

MONITORING

§60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly

NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad (Eq. 1)$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq. 2)$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (Eq. 3)$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and $3.413 \times 10_6$ = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \qquad (Eq. 4)$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for

noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

REPORTING

§60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a “4-hour rolling average NO_X emission rate” is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a “30-day rolling

average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§60.4385 How are excess emissions and monitoring downtime defined for SO2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

PERFORMANCE TESTS

§60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad (Eq. 5)$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies that you may use to conduct the performance tests.

(1) The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the affected facility. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter may be used.

(2) Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see §60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see §60.17). For manual sampling of liquid fuels, follow GPA 2174 or the procedures for manual pipeline sampling in section 14 of ASTM D4057 (both incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, D5453, D5623, or D7039 (all incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see §60.17).

(3) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad (Eq. 6)$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664 × 10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(4) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

[71 FR 38497, July 6, 2006, as amended at 85 FR 63410, Oct. 7, 2020]

DEFINITIONS

§60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

Attachment J

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on July 18, 2024]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Source:89 FR 40035, May 9, 2024, unless otherwise noted.

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for

sources that do not qualify under paragraphs (c) and (d) of this section), where the term “gross or net energy output” is used, the term that applies to you is “gross energy output.”

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term “gross or net energy output” is used, the term that applies to you is “net energy output.” Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (e.g., non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard\ = \frac{(50\ \mathrm{x}\ HTIP_{ng}) + (69\ \mathrm{x}\ HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * \left[\frac{HIER_A}{HIER_{NG}}\right]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for “valid operating hours”, as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F-7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of 40 CFR part 98. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as “stack operating hours” (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the “stack operating time” (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this

section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.,* operating hours for which:

(i) "Valid data" (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii) $$(Pt)_{PS} = \frac{Q_m \times H}{CF} \text{ (Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)

(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)

(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not “valid operating hours” (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)

(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions) of this part.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388-99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as “cogeneration”) means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22-2014, ASME PTC 46-1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.,* onsite photovoltaics), integrated energy storage (*e.g.,* onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may,

however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP-011-2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	**CO_2 emission standard**
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Table 2 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After May 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

Table 3 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)-(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)-(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a Significant Source Modification and Significant Permit Modification

Source Background and Description

Source Name:	**Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T 073-45762-00008**
Operation Permit Issuance Date:	**October 13, 2023**
Significant Source Modification No.:	**073-47965-00008**
Significant Permit Modification No.:	**073-48085-00008**
Permit Reviewer:	**Hachem Ismaili Alaoui**

On November 19, 2024, the Office of Air Quality (OAQ) had a notice posted on IDEM's website (https://www.in.gov/idem/public-notices/), stating that Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station had applied for a Significant Source Modification and Significant Permit Modification to construct and operate three (3) aero-derivative natural gas fired simple cycle turbines, one (1) frame-type natural gas-fired simple cycle combustion turbine, one (1) diesel emergency generator, and one (1) diesel emergency fire pump. The notice also stated that the OAQ proposed to issue a Significant Source Modification and Significant Permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

The Technical Support Document (TSD) is used by IDEM, OAQ for historical purposes. IDEM, OAQ does not make any changes to the original TSD, but the Permit will have the updated changes. The comments and revised permit language are provided below with deleted language as ~~strikeouts~~ and new language **bolded**.

NIPSCO Comments and Responses

On December 19, 2024, Gurinder Saini, a consultant for Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station (NIPSCO), submitted comments to IDEM, OAQ on the draft Significant Source Modification and Significant Permit Modification.

NIPSCO Comment 1:

Condition D.0.1 includes a typographical error in terms of the units' ID numbers. D.0.1 should be revised as follows:

(a) The combined total HAPs emissions from the combustion turbines (16A, 16B, 19A, **19B** ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined formaldehyde emissions from the combustion turbines (16A, 16B, 19A, **19B** ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency

generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Response to NIPSCO Comment 1:

IDEM agrees with the recommended changes, since they are typographical errors. The permit has been revised as requested above or as follows:

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

*****

(a) The combined total HAPs emissions from the combustion turbines (16A, 16B, 19A, **19B** ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined formaldehyde emissions from the combustion turbines (16A, 16B, 19A, **19B**, ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

NIPSCO Comment 2:

In the equipment description sections of the draft permit, the four new simple cycle combustion turbines (Units 19A, 19B, 19C, and 20) are noted as "[u]nder 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities." We disagree with the inclusion of the text 'intermediate mode affected facilities' in the description part of the permit and request deletion of the same. We recognize that the descriptions in the permit are NOT enforceable. However, we believe the inclusion of this language is arbitrary and unnecessary under the applicable NSPS 40 CFR 60 Subpart TTTTa. First, the term 'intermediate mode' does not exist in the regulatory provisions of NSPS 40 CFR 60 Subpart TTTTa. Therefore, this is an arbitrary creation of a category in the draft permit by IDEM and is inconsistent with the regulatory compliance option category. Secondly, the regulation provides flexibility for the affected facilities to switch from one compliance option category to another. For example, if a CT was cofiring hydrogen to meet the 'Intermediate Load combustion turbine' CO2 emission limitation, the NSPS regulations allow such a unit to stop firing hydrogen and meet the capacity factor criteria for 'Low Load combustion turbine' and meet the heat input-based limit. Thereafter, such a unit could reverse the compliance option category and elect to comply with the Intermediate Load combustion turbine standard. The inclusion of the compliance option category in description is unnecessary and could become obsolete if NIPSCO chooses to change the compliance option. In addition, it would create an administrative burden both on the agency and the source that is not useful for compliance with the applicable standard. Relevant applicable requirements are specifically listed under condition E.11.2 of the draft permit and have been incorporated by reference. We do not believe that there is any obligation on the part of the permittee to update the description of the affected facility in the permit for the purposes of NSPS compliance option when IDEM has incorporated the entire relevant provisions of the standard by reference in the permit.

Response to NIPSCO Comment 2:

IDEM agrees that the term 'intermediate mode" does not exist in 40 CFR 60, Subpart TTTTa. The correct terminology is "intermediate load".

Section E.11.2 of the permit incorporates the applicable requirements under 40 CFR 60, Subpart TTTTa. To identify what requirements are applicable upon startup of the four new simple cycle

combustion turbines (Units 19A, 19B, 19C, and 20), the proposed operating load must be identified.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

*****

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

*****

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

SECTION E.10 NSPS

Emissions Unit Description:

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

SECTION E.11 NSPS

Emissions Unit Description:

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)

ORIS Code: 994

Emissions Unit Description:

*****

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are ~~intermediate mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

NIPSCO Comment 3:

On December 13, 2024, the U.S. EPA published a proposal for a new NSPS as 40 CFR 60 Subpart KKKKa for combustion/gas turbines. The new standard will be applicable to combustion/gas turbines that would be newly constructed, reconstructed, or modified after December 13, 2024. NIPSCO entered a memorandum of understanding ("MOU") with General Electric Vernova Operations LLC on March 29, 2024. This MOU is for the fabrication of the four CTs (three Aero units and one Frame unit) for installation at the R.M. Schahfer site. The MOU includes contractual provisions necessary for NIPSCO to continue planning to allow for a continuous program of construction to be completed within a 'reasonable time.' It includes penalties associated with cancellation of the MOU by NIPSCO. In accordance with 40 CFR § 60.2, definition of 'commenced,' for purposes of NSPS provisions, NIPSCO has determined that the construction on the four combustion turbines under consideration in the draft permit here commenced on March 29th, 2024. Since, the construction of the CTs commenced prior to the publication date of the proposed NSPS 40 CFR 60 Subpart KKKKa, these units are grandfathered for purposes of this standard and are considered 'existing facilities.' We request that IDEM include this non-applicability determination in the ATSD for this permit action.

Response to NIPSCO Comment 3:

40 CFR 60, Subpart KKKKa applies to combustion/gas turbines that would be newly constructed, reconstructed, or modified after December 13, 2024. NIPSCO has provided information the above information indicating that construction of four combustion turbines (Units 19A, 19B, 19C, and 20) commenced prior to December 13, 2024. Based on the provided information, commencement of construction occurred prior to December 13, 2024 and the proposed four combustion turbines (Units 19A, 19B, 19C, and 20) are not subject to the requirements of 40 CFR 60, Subpart KKKKa.

EPA Comments and Responses

On December 20, 2024, Priyanka Painuly from EPA submitted comments to IDEM, OAQ on the draft Significant Source Modification and Significant Permit Modification.

EPA Comment 1:

Condition D.0.1 (c) [page 34 of 112] of the draft permit specifies that coal fired boilers, Unit 17 and Unit 18, shall be permanently shutdown and decommissioned from the facility. However, this requirement doesn't appear enforceable without a timeframe for the shutdown/decommissioning of Unit 17 and Unit 18. Please add a timeframe for Unit 17 and Unit 18 shutdown, so the facility doesn't simultaneously operate Unit 17, Unit 18 and the proposed turbines, Unit 19A, Unit 19B, Unit 19C, and Unit 20 and violate the permit limits and conditions. For example, because the shutdown is not immediately after the issuance of this permit, you could specify: "Unit 17 and Unit 18, shall be permanently shutdown and decommissioned from the facility prior to the start of operation of the simple cycle combustion turbines, Unit 19A, Unit 19B, Unit 19C, and Unit 20".

Response to EPA Comment 1:

IDEM agrees with the recommended changes. The permit has been revised as follows:

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

*****

(c) **Upon the commencement of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20,** ~~The~~ **the** two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from the source.

EPA Comment 2:

It appears that the HAP emission calculations as specified in Condition D.0 are not necessary/applicable immediately after the permit issuance. The facility will comply with Condition D.0. [page 34 of 112] after the start of operation of the simple cycle combustion turbines, Unit 19A, Unit 19B, Unit 19C, and Unit 20. Please update the permit to clarify this (preferably in Condition D.0) to avoid confusion regarding the applicability of Condition D.0.

Response to EPA Comment 2:

IDEM agrees with the recommended changes. The permit has been revised as follows:

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

*****

(d) The limits in paragraphs (a) and (b) will be effective after the permanent shutdown and decommissioning of the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18 and the start of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20.

EPA Comment 3:

Condition D.13.2 [page 62 of 112] limits the VOC emissions from Unit 20, during normal operation, to not exceed 6.5 lb/hr per 326 IAC 8-1-6. Adding a one-time VOC test is recommended for Unit 20 to demonstrate compliance with Indiana's VOC BACT limit.

Response to EPA Comment 3:

IDEM agrees with the recommended changes. A one-time VOC stack testing is necessary to verify the VOC emission rate from the natural gas-fired combustion turbine, identified as Unit 20, to verify VOC BACT limit. The permit has been revised as follows:

D.13.3 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for NOx **and demonstrate compliance with VOC limitation under Condition D.13.2(b)**, not later than 180 days after the startup of the following emission units, the Permittee shall perform NOx **and VOC** testing on the following emission units:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	NOx (45.90 lb/hr)	One time

Frame type combustion turbine	Unit 20	NOx (139.80 lb/hr) **VOC (6.50 lb/hr)**	One time

EPA Comment 4:

Condition D.13.1 [page 62 of 112] specifies PSD minor limits for PM and VOC. Condition D.13.5, specifies equations, and emission rates to be utilized for compliance determination with PSD minor limits established in Condition D.13.1. EPA recommends adding a one-time performance test to demonstrate compliance with the established PM and VOC emission rates, for any one of the Units 19A, 19B, and 19C, operating under normal scenario.

Response to EPA Comment 4:

IDEM-OAQ requires sources to perform one-time stack testing to verify emission rates provided by the source when the proposed emission rates are greater than those published by EPA in AP-42 chapters. IDEM-OAQ compared the emission rates for PM and VOC proposed by NIPSCO with PM and VOC emission rates based on AP-42 chapter 3.1 (Stationary Gas Turbines) and found that PM and VOC emission rates proposed by NIPSCO are greater than those calculated based on AP-42 emission factors.

Emission rates proposed by the source for Units 19A, 19B, and 19C are:
PM = 4.90 lb/hr
VOC = 5,40 lb/hr
Heat input to each Unit is 519 MMBtu/hr

Emission rates based on AP-42 emission factors
PM = 0.0019 (lb/MMBtu) * 519 (MMBtu/hr) = 0.99 lb/hr
VOC = 0.0021 (lb/MMBtu) * 519 (MMBtu/hr) = 1.09 lb/hr

0.0019 lb/MMBtu = Emission factor for PM, AP-42, chapter 3.1, table 3.1-2a
0.0021 lb/MMBtu = Emission factor for VOC, AP-42, chapter 3.1, table 3.1-2a

Therefore, IDEM-OAQ believes that NIPSCO are not required to perform any stack testing for PM and VOC for Units 19A, 19B, and 19C. No changes were made as a result of this comment.

EPA Comment 5:

In Appendix A, page 2 of 20 of the TSD, the facility inadvertently left out GHG emissions estimates from the turbines 19A, 19B, 19C and 20. The facility estimated GHG emissions for all other units included in the application. Please request the facility to provide GHG estimates for the proposed turbines Unit 19A, Unit 19B, Unit 19C, and Unit 20, and update the emission calculations in Appendix A.

Response to EPA Comment 5:

IDEM agrees with the recommended changes. The calculations have been updated as requested and provided as ATSD calcs.

Additional Changes

IDEM, OAQ has decided to make additional revisions to the permit as described below, with deleted language as ~~strikeouts~~ and new language **bolded**.

(a) Correct typographical errors

D.13.8 Record Keeping Requirements

*****

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.**5**~~6~~(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13. **5**~~6~~ (b).

IDEM Contact

(a) If you have any questions regarding this permit, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled Potential to Emit (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	69,589	16,006	16,006	95,079	9,383	46.91	390.95	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	69,589	16,006	16,006	95,079	9,383	46.91	390.95	3,768,728	1211.34	938.28	HCl
Turbine 16A	41.92	41.92	41.92	21.49	2,032	13.34	520.78	705,653	7.90	4.51	Formaldehyde
Turbine 16B	41.92	41.92	41.92	21.49	2,032	13.34	520.78	705,653	7.90	4.51	Formaldehyde
Turbine 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	269,027	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	1,252,349	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**139393**	**32227**	**32225**	**190236**	**24056**	**259**	**3010**	**10522968**	**2466**	**1877**	**HCl**

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Limited Potential to Emit (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	269,027	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	1,252,349	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**1129**	**32162**	**32160**	**190203**	**23004**	**184**	**2206**	**9433877**	**2454**	**1896**	**HCl**

Limited Potential to Emit After Removal of Boilers Unit 17 and Unit 18 (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	269,027	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	1,252,349	10.82	4.82	Formaldehyde
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**81.46**	**147.29**	**147.28**	**44.19**	**2153.22**	**90.02**	**1424.50**	**1896421.36**	**<25**	**<10**	**Formaldehyde**

Appendix A: Emission Calculations
Modofication Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled PTE of New Units (ton/yr)										
	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	Total HAPs	Single HAPs	
Turbine 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	10.82	4.82	Formaldehyde
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	0.008	0.004	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.002	0.001	Benzene
Total	***124.49***	***124.69***	***124.68***	***33.94***	***1206.60***	***135.83***	***1169.94***	***26.79***	***16.91***	**Formaldehyde**

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Contemporaneous Emissions Decreases

Existing Emission Units (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Unit 14 and Unit 15							
Baseline Actual Emissions	102.30	400.91	361.89	310.73	2166.44	82.31	4834.98
Baseline period 2018-2019							
BAE	***-102.30***	***-400.91***	***-361.89***	***-310.73***	***-2166.44***	***-82.31***	***-4834.98***

Contemporaneous Emissions Increases

Emissions (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Temporary Boiler Operation							
Actual Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17
Period of emissions 2023							
BAE	***0.11***	***0.44***	***0.44***	***0.03***	***2.13***	***0.32***	***2.17***

New Emission Units (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C							
Potential Emissions	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*36.49*	*71.72*	*71.72*	*13.24*	*595.38*	*31.45*	*710.10*
ATP	***36.49***	***71.72***	***71.72***	***13.24***	***595.38***	***31.45***	***710.10***
Turbine 20							
Potential Emissions	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*24.56*	*52.50*	*52.50*	*20.52*	*602.99*	*48.25*	*455.17*
ATP	***24.56***	***52.50***	***52.50***	***20.52***	***602.99***	***48.25***	***455.17***
Emergency Generator EDG1							
Potential Emissions	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.24*	*0.29*	*0.28*	*0.01*	*7.69*	*1.54*	*4.20*
ATP	***0.24***	***0.29***	***0.28***	***0.01***	***7.69***	***1.54***	***4.20***
Emergency Fire Pump FP1							
Potential Emissions	0.03	0.18	0.18	0.17	0.54	0.11	0.47
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.03*	*0.18*	*0.18*	*0.17*	*0.54*	*0.11*	*0.47*
ATP	***0.03***	***0.18***	***0.18***	***0.17***	***0.54***	***0.11***	***0.47***

Grey Cells are limited emissions

New Emissions Units Potential to Emit (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Turbine 20	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Emergency Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47
ATP	***61.31***	***124.69***	***124.68***	***33.94***	***1206.60***	***81.35***	***1169.94***

Net Emissions Increase (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
ATP for New Emission Units	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94
Contemporaneous Increases	0.11	0.44	0.44	NA	2.13	0.32	2.17
Contemporaneous Decreases	-102.30	-400.91	-361.89	NA	-2166.44	-82.31	-4834.98
Net Emissions Increase	**-40.88**	**-275.77**	**-236.77**	**33.94**	**-957.71**	**-0.65**	**-3662.87**
Significance Threshold (tpy)	25	15	10	40	40	40	100

Unit 14 was shutdown in July 2020 and removed fom the permit in November 2023. Unit 15 was shutdown in September 2021 and removed from the permit in November 2023. The period between the shutdown/removal of Units 14 and 15 and the construction and operation of the new units (Turbines 19A, 19B, 19C, and 20, Engine EDG1, and Fire Pump FP1) will be within the contemporaneous peride. Therefore, emissions decrease for

PM and VOC should be subject to the 40% capacity factor limited to avoid being subject to PSD BACT analysis

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
99.9	1020	858.0

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	37.1 **see below	5.5	37.7
Potential Emission in tons/yr	0.82	3.26	3.26	0.26	15.92	2.36	16.17

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.50E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	9.0E-04	5.1E-04	3.2E-02	0.77	1.5E-03	**0.81**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	2.1E-04	4.7E-04	6.0E-04	1.6E-04	9.0E-04	**2.4E-03**
Methodology is the same as above.					**Total HAPs**	**0.81**
The five highest organic and metal HAPs emission factors are provided above.					**Worst HAP**	**0.77**
Additional HAPs emission factors are available in AP-42, Chapter 1.4.						

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	51,478	0.99	0.94
Summed Potential Emissions in tons/yr	51,480		
CO2e Total in tons/yr	51,784		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #17

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %		Weight %
Sulfur =	3.2	Ash =	8.90

Uncontrolled PTE	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*				*10,425*		

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 17.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1yr * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #18

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)	Potential Throughput (ton/hr)
3967	11111	1.56E+06	1.79E+02

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Uncontrolled PTE

	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*	--	--	--	*10,425*	--	--

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 18.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1year * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/22)

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of C	Potential Throughput (ton/yr)
3967	11111	1560000

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Limited

	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7 (10A)	20.47 (2.3A)	3.6 *(38S)*	4.4	0.06	6.00
Potential Emission in tons/yr	524	16,006	2,852	3,475	47	4,691

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A: Emission Calculations
Natural Gas Combustion Only
Turbine 16A

Company Name: **NIPSCO - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-47965-00008**
Significant Permit Modification No: **073-48085-00008**
Reviewer: **Hachem Ismaili Alaoui**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450.0	1020	12452.9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41.92	41.92	41.92	21.49	2032.32	13.34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Uncontrolled Emission Factor in lb/MMBtu * 2000hours/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1.2E-05	4.3E-07	7.10E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4.06E-01	8.26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4.0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8.26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O
Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 200hours/yr /2000lb/ton

Appendix A: Emission Calculations
Natural Gas Combustion Only
Turbine 16B

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450.0	1020	12452.9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41.92	41.92	41.92	21.49	2032.32	13.34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor in lb/MMBtu * 2000hrs/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1.2E-05	4.3E-07	7.1E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4.06E-01	8.26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4.0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8.26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/yr * 1ton/2,000 lb
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 2000hours/1 year * 1ton/2000lbs

Appendix A: Emissions Calculations
Turbines 19A, 19B, and 19C

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation			HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Maximum Heat input per Turbine	519	MMBtu/hr	1020	4457.29
Output (gross)	55	MW		
Number of Turbines:	3			
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)		
Number of SU/SD	4	events per day		
CT operation	1,460	events/year		
Startup duration for CT*	0.17	hour		
Shutdown duration for CT**	0.15	hour		
Heat input during events***	73.60	MMBtu/event		
Worst case sulfur in NG	0.50	gr/100 cf		
SO2 emission factor	0.002	lb/MMBtu		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 turbines)
PM	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM10	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM2.5	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	12.92 tons/yr	0.32 tons/yr	13.24 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	571.29 tons/yr	24.09 tons/yr	595.38 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	67.21 tons/yr	3.07 tons/yr	70.28 tons/yr
CO	50.70 lb/hr	36.10 lb/event	631.04 tons/yr	79.06 tons/yr	710.10 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 Turbines)
PM	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	28.38 tons/yr	3.07 tons/yr	31.45 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors		***Unlimited HAP Emissions***		
Hexane	2.50E-04	lb/MMBtu	1.70	tons/yr	
1,3-Butadiene	4.3E-07	lb/MMBtu	0.00	tons/yr	
Acetaldehyde	4.00E-05	lb/MMBtu	0.27	tons/yr	
Acrolein	6.40E-06	lb/MMBtu	0.04	tons/yr	
Benzene	1.20E-05	lb/MMBtu	0.08	tons/yr	
Ethylbenzene	3.20E-05	lb/MMBtu	0.22	tons/yr	
Formaledyhyde	0.920	lb/hr	12.09	tons/yr	
Napathalene	1.30E-06	lb/MMBtu	0.01	tons/yr	
PAH	2.20E-06	lb/MMBtu	0.02	tons/yr	
Proplene Oxide	2.90E-05	lb/MMBtu	0.20	tons/yr	
Toluene	1.30E-04	lb/MMBtu	0.89	tons/yr	
Xylene	6.40E-05	lb/MMBtu	0.44	tons/yr	
	Total HAP Emissions		**15.96**	**tons/yr**	
	Single Worst HAP Emission		**12.09**	**tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) = 1.77E-03
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	267,438	5.1	4.9
Summed Potential Emissions in tons/yr	267,448		
CO2e Total in tons/yr	269,027		

Methodology
The N2O Emission Factor for uncontrolled is 2.2.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emissions Calculations
Turbine 20

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation			HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Maximum Heat input per Turbine	2416	MMBtu/hr	1020	20749.18
Output (gross)	247	MW		
Number of Turbines:	1			
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)		
Number of SU/SD	2	events per day		
CT operation	730	events/year		
Startup duration for CT	0.35	hour		
Shutdown duration for CT	0.25	hour		
Heat input during events	564	MMBtu/event		
Worst case sulfur in NG	0.50	gr/100 cf		
SO2 emission factor	0.002	lb/MMBtu		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
PM10	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
PM2.5	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	20.11 tons/yr	0.41 tons/yr	20.52 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	581.71 tons/yr	21.28 tons/yr	602.99 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	27.05 tons/yr	36.87 tons/yr	63.91 tons/yr
CO	51.10 lb/hr	664.50 lb/event	212.63 tons/yr	242.54 tons/yr	455.17 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	11.39 tons/yr	36.87 tons/yr	48.25 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors		***Unlimited HAP Emissions***		
Hexane	2.50E-04	lb/MMBtu	2.65	tons/yr	
1,3-Butadiene	4.3E-07	lb/MMBtu	0.00	tons/yr	
Acetaldehyde	4.00E-05	lb/MMBtu	0.42	tons/yr	
Acrolein	6.40E-06	lb/MMBtu	0.07	tons/yr	
Benzene	1.20E-05	lb/MMBtu	0.13	tons/yr	
Ethylbenzene	3.20E-05	lb/MMBtu	0.34	tons/yr	
Formaledyhyde	1.10	lb/hr	4.82	tons/yr	
Napathalene	1.30E-06	lb/MMBtu	0.01	tons/yr	
PAH	2.20E-06	lb/MMBtu	0.02	tons/yr	
Proplene Oxide	2.90E-05	lb/MMBtu	0.31	tons/yr	
Toluene	1.30E-04	lb/MMBtu	1.38	tons/yr	
Xylene	6.40E-05	lb/MMBtu	0.68	tons/yr	
	Total HAP Emissions		**10.82**	**tons/yr**	
	Single Worst HAP Emission		**4.82**	**tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) = 4.55E-04
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	1,244,951	23.9	22.8
Summed Potential Emissions in tons/yr	1,244,997		
CO2e Total in tons/yr	1,252,349		

Methodology
The N2O Emission Factor for uncontrolled is 2.2.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Gypsum Material Handling System
Radial Stackers

Company Name: **NIPSCO - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-47965-00008**
Significant Permit Modification No: **073-48085-00008**
Reviewer: **Hachem Ismaili Alaoui**

Parameter		Value	Units	Source / Basis
New stacker throughput capacity	=	220	tons/hour	For each stacker. Information from the S&L Study 3-29-2012
New maximum throughput per stacker	=	1,927,200	tons/year	Based on 8,760 hours/year
Number of Stackers for Replacement	=	2		
Number of drop pont per stacker	=	1	Number	One drop point from stacker to pile
Moisture Content (M)	=	4.80	%	Conservative estimate
Annual Mean Wind speed (U)	=	10.00	mph	From RMS Calculations for Material Handling Emissions
PM Particle size multiplier (kP)	=	0.740	dimensionl	Ref. 1
PM10 Particle size multiplier (kP)	=	0.350	dimensionl	Ref. 1
PM2.5 Particle size multiplier (kP)	=	0.053	dimensionl	Ref. 1
PM Emission Factor	=	0.00171	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM10 Emission Factor	=	0.00081	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM2.5 Emission Factor	=	0.00012	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1

PTE Calculation Results

	PTE (TPY)		
Emission Unit	PM	PM10	PM2.5
Stacker 7MX04G-RS	1.65	0.78	0.12
Stacker 8MX04G-RS	1.65	0.78	0.12
Total	3.30	1.56	0.24

References:
1. EPA AP-42 Chapter 13.2.4; 11/2006.

Methodology:

PM/PM10/PM2.5 PTE (TPY) = New maximum throughput per stacker (tons/year) * Emission Factor (lb/ton/drop) * 1ton/2000lbs

Appendix A: Emission Calculations
Unit 17 & Unit 18
Activated Carbon Injection Grid

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Parameter		Value	Units	Source / Basis
Unit 17 AC Throughput Annual	=	365	tons/year	Design basis[1]
Unit 18 AC Throughput Annual	=	365	tons/year	Design basis[1]
PM Emission Factor	=	100%	fraction	AC particles in the 15 to 25 micrometer range[2]
PM10 Emission Factor	=	100%	fraction	Assumed 100% fractures to PM10[3]
PM2.5 Emission Factor	=	100%	fraction	Assumes 100% fractures to PM2.5[3]
Control Efficiency	=	99.75%		Use of ESP & Wet Scrubber[4]

PTE Calculation Results

	PTE, Controlled					
	Unit 17 (TPY)			Unit 18 (TPY)		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
ACI Stack Emissions	0.91	0.91	0.91	0.91	0.91	0.91

[1] Design basis establishes injection rate of ~2,000 pounds per day per unit.

[2] Activated Carbon Injection for Mercury Control on Industrial Coal-Fired Boilers Richard Miller Vice President Business Development ADA Environmental Solutions Co-Chairman ICAC Mercury Committee.

[3] Conservative assumption as worst case scenario.

[4] ESP design efficincies approximately 99.5%. Conservatively assumed that wet scrubber will achieve 50% additional reduction.

Appendix A: Emission Calculations
Fugitive Dust Emissions - Unpaved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Unpaved Roads at Industrial Site
The following calculations determine the amount of emissions created by unpaved roads, based on 8,760 hours of use and AP-42, Ch 13.2.2 (11/2006).

Vehicle Information (provided by source)

Type	Maximum number of vehicles	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	264	0.050	0.0	2.6
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	264	0.050	0.0	2.6
		Totals	**0.3**		**6.6**			**0.0**	**5.1**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.05 miles/trip

Unmitigated Emission Factor, Ef = k*[(s/12)^a]*[(W/3)^b] (Equation 1a from AP-42 13.2.2)

	PM	PM10	PM2.5	
where k =	4.9	1.5	0.15	lb/mi = particle size multiplier (AP-42 Table 13.2.2-2 for Industrial Roads)
s =	4.8	6.0	6.0	% = mean % silt content of unpaved roads (AP-42 Table 13.2.2-1 Iron and Steel Production)
a =	0.7	0.9	0.9	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)
W =	23.5	23.5	23.5	tons = average vehicle weight
b =	0.45	0.45	0.45	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [(365 - P)/365] (Equation 2 from AP-42 13.2.2)
Mitigated Emission Factor, Eext = E * [(365 - P)/365]
where P = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.2-1)

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	6.51	2.03	0.20	lb/mile
Mitigated Emission Factor, Eext =	4.37	1.36	0.14	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.01**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Mitigated PTE (Before Control) (tons/yr) = (Maximum one-way miles (miles/yr)) * (Mitigated Emission Factor (lb/mile)) * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = (Mitigated PTE (Before Control) (tons/yr)) * (1 - Dust Control Efficiency)

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particulate Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Paved Roads at Industrial Site
The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	1056	0.200	0.0	10.2
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	1056	0.200	0.0	10.2
		Totals	**0.3**		**6.6**			**0.1**	**20.4**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.20 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	23.5	23.5	23.5	tons = average vehicle weight
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	2.177	0.435	0.1069	lb/mile
Mitigated Emission Factor, Eext =	1.998	0.400	0.0981	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.02**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (Before Control) (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = [Mitigated PTE (Before Control) (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

One (1) diesel fire pump 350 HP

Output Horsepower Rating (hp)	350.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	175,000

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.0022	0.0021	0.0310	0.0025	0.0067
Potential Emission in tons/yr	0.19	0.19	0.19	0.18	2.71	0.22	0.58

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.71E-04	2.51E-04	1.75E-04	2.39E-05	7.23E-04	4.70E-04	5.67E-05	1.03E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.37E-03**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Green House Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	1.01E+02	4.05E-03	8.10E-04

Summed Potential Emissions in tons/yr	**1.01E+02**
CO2e Total in tons/yr	**1.01E+02**

Methodology
Emission Factors are from AP42 (Supplement B 10/96), Tables 3.3-1 and 3.3-2
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)
Emergency Engine EDG1

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	2922.0	NSPS Subpart IIII Emission Standards based on a: 2007	model year emergency engine
Output Horsepower Rating (kw)	2178.9		
Maximum Hours Operated per Year	500	(emergency generator or fire pump)	
Potential Throughput (hp-hr/yr)	1,461,000		
Potential Throughput (kw-hr/yr)	1,089,468		
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))	

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2 *(.00809S)*	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		4.01E-04	3.89E-04	1.21E-05			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				6.40	1.28	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0.29	0.28	0.01			
Based on g/kw-hr Emission Factor	0.24				7.69	1.54	4.20
Potential Emission in tons/yr	**0.24**	**0.29**	**0.28**	**0.01**	**7.69**	**1.54**	**4.20**

*The PM10 and PM2.5 emission factors for are from AP-42 Table 3.4-2. The PM10 emission factor is the sum of filterable PM10 and condensable particulate. The PM2.5 emission factor is the sum of filterable particulate less than 3 um and condensable particulate. Emission factors in lb/hp-hr were calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	3.97E-03	1.44E-03	9.87E-04	4.03E-04	1.29E-04	4.03E-05	1.08E-03

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Potential Emission of Total HAPs (tons/yr)	**8.05E-03**	
Worste Single HAP	**3.97E-03**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.16E+00	6.35E-05	9.30E-06
Potential Emission in tons/yr	8.47E+02	4.64E-02	6.79E-03

Summed Potential Emissions in tons/yr	**8.47E+02**
CO2e Total in tons/yr	**8.51E+02**

Methodology
CO2 Emission Factor is from AP 42 (Supplement B 10/96) Table 3.4-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) based on 11/29/2013 federal GWPs= CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)
Fire Pump FP1

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

NSPS Subpart IIII Emission Standards based on a: 2009 model year emergency engine

Output Horsepower Rating (hp)	327.0	
Output Horsepower Rating (kw)	243.8	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	163,500	
Potential Throughput (kw-hr/yr)	121,922	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		0.0022	0.0022	0.00205			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				4.00	0.80	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0.18	0.18	0.17			
Based on g/kw-hr Emission Factor	0.03				0.54	0.11	0.47
Potential Emission in tons/yr	**0.03**	**0.18**	**0.18**	**0.17**	**0.54**	**0.11**	**0.47**

*PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.34E-04	2.34E-04	1.63E-04	2.24E-05	6.75E-04	4.39E-04	5.29E-05	9.61E-05

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.22E-03**	
Worste Single HAP	**6.75E-04**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.
Output Horsepower Rating (kw) = Output Horsepower Rating (hp) * (0.7457 kw/hp)
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Throughput (kw-hr/yr) = [Output Horsepower Rating (kw)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] * [ton/2,000 lbs]
Potential Emission (tons/yr) = [Potential Throughput (kw-hr/yr)] * [Emission Factor (g/kw-hr)] * [lb / 453.592 g] * [ton/2,000 lbs]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	9.40E+01	3.78E-03	7.57E-04

Summed Potential Emissions in tons/yr	**9.40E+01**
CO2e Total in tons/yr	**9.43E+01**

Methodology
CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential

Appendix A: Emission Calculations
Unit 14 & Unit 15 Actual Emissions

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Baseline Actual Emissions for Contemporaneous Changes

	2018 Emissions (ton/yr)		2019 Emissions (ton/yr)		BAE* (ton/yr)		Total
Pollutant	**Unit 14**	**Unit 15**	**Unit 14**	**Unit 15**	**Unit 14**	**Unit 15**	
PM	43.9	59.8	64.2	36.8	54.0	48.3	**102.3**
PM10	139.9	301.1	142.7	218.2	141.3	259.6	**400.9**
PM2.5	119.3	284.2	112.5	207.9	115.9	246.0	**361.9**
SO2	163.4	211.4	115.0	131.7	139.2	171.5	**310.7**
NOx	760.2	1,668.6	676.5	1,227.7	718.3	1448.1	**2166.4**
VOC	50.4	41.5	41.8	31.0	46.1	36.2	**82.3**
CO	232.8	5,262.4	192.4	3,982.3	212.6	4622.3	**4835.0**

* BAE: Baseline Actual Emissions

Emissions reported in the site emissions inventories

	2018	2019	
Unit 15 coal heat input	25,545,640	19,331,471	MMBtu
CO factor for Unit 15	0.41	lb/MMBtu	
CO stack test for Unit 15 - December 3, 2019			

	2018	2019	BAE	
Unit 15 CO emissions	5,262.4	3,982.3	4,622.3	TPY

Notes
PM, PM10, PM2.5 NOx, and VOC emissions from Unit 14 and Unit 15 and CO emissions from Unit 14, as reported to IDEM in the emissions inventories, during the 2018-19 period are selected as Baseline Actual Emissions (BAE).

A December 2019 CO stack test for Unit 15 demonstrates a CO emission rate of 0.41 lb/MMBtu of heat input to the unit. NIPSCO used the coal combustion heat input for 2018 and 2019 for Unit 15 and the CO emission factor from the stack test to estimate actual CO emissions as BAE for this unit.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: **NIPSCO - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-47965-00008**
Significant Permit Modification No: **073-48085-00008**
Reviewer: **Hachem Ismaili Alaoui**

Actual Throughput for year 2023

MMCF/yr
115.0

	Pollutant							
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO	CO2e
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	37.1 **see below	5.5	37.7	119,349
Potential Emission in tons/yr	0.11	0.44	0.44	0.03	2.13	0.32	2.17	6862.56

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.
CO2e from 40 CFR Part 98 Subpart A Table A-1 and Subpart C Tables C-1 and C-2.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Source Modification and Significant Permit Modification

Source Description and Location

Source Name:	**Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T 073-45762-00008**
Operation Permit Issuance Date:	**October 13, 2023**
Significant Source Modification No.:	**073-47965-00008**
Significant Permit Modification No.:	**073-48085-00008**
Permit Reviewer:	**Hachem Ismaili Alaoui**

Source Definition

This stationary source consists of an electric utility generating station with an on-site contractor that processes and moisture conditions fly ash:

(1) The electric utility generating station, Northern Indiana Public Service Company LLC, R.M. Schahfer Station, is the primary operation and is located at 2723 East 1500 North, Wheatfield, Indiana; and

(2) The fly ash processor, Headwaters Resources, Inc., is the supporting operation and is located at 2723 East 1500 North, Wheatfield, Indiana.

IDEM has determined that Northern Indiana Public Service Company LLC, R.M. Schahfer Station and Headwaters Resources, Inc., will be considered one source as defined by 326 IAC 2-7-1(22) based on contractual control. Therefore, the term “source” in the Part 70 documents refers to both Northern Indiana Public Service Company LLC, R.M. Schahfer Station and Headwaters Resources, Inc., as one source.

Separate Part 70 Operating permits will be issued to Northern Indiana Public Service Company LLC, R.M. Schahfer Station and Headwaters Resources, Inc., solely for administrative purposes.

This determination was initially made under Part 70 Operating Permit No. 73-23909-00040, issued on July 24, 2007.

Existing Approvals

The source was issued Part 70 Operating Permit Renewal No. 073-45762-00008 on November 13, 2023. There have been no subsequent approvals issued.

County Attainment Status

The source is located in Jasper County.

Pursuant to amendments to Indiana Code IC 13-17-3-14, effective July 1, 2023, a federal regulation that classifies or amends a designation of attainment, nonattainment, or unclassifiable for any area in Indiana under the federal Clean Air Act is effective and enforceable in Indiana on the effective date of the federal regulation.

Pollutant	Designation
SO_2	Unclassifiable or attainment effective April 9, 2018, for the 2010 primary 1-hour SO_2 standard. Better than national secondary standards effective March 3, 1978.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective August 3, 2018, for the 2015 8-hour ozone standard.
$PM_{2.5}$	Unclassifiable or attainment effective April 15, 2015, for the 2012 annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour $PM_{2.5}$ standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO_2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_x emissions are considered when evaluating the rule applicability relating to ozone. Jasper County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Jasper County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NOx emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Jasper County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a fossil fuel-fired steam electric power plant of more than 250 MMBtu/hour heat input, it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1) or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is

invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Source Status - Existing Source

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions Prior to Modification (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[3]**	**Total HAPs**
Total PTE of Entire Source Including Fugitives*	**1067.83**	**32037.12**	**32035.79**	**190168.93**	**21781.26**	**100.14**	**1020.29**	**1876.29**	**2426.70**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."
[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[3]Single highest source-wide HAP (HCl)
*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant(s), PM, PM10, PM2.5, SO2, NOx, VOC, and CO, is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) This existing source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs.

(c) These emissions are based on the TSD of Part 70 Permit Renewal No. 073-45762-00008, issued on November 13, 2023.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed an application submitted by Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station on June 17, 2024, relating to the installation of four (4) natural gas-fired simple cycle combustion turbines, one (1) diesel emergency generator, and one (1) diesel emergency fire pump.

The following is a list of the new emission units and pollution control device(s):

(a) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(b) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(c) One (1) diesel emergency generator, Identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(d) One (1) diesel emergency fire pump, Identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Project Aggregation

Northern Indiana Public Service Company LLC, R.M. Schahfer Station submitted the following permit application to IDEM. When a major source for Prevention of Significant Deterioration (PSD) and/or Emission Offset (EO) submits an application for an amendment or modification, IDEM, OAQ reviews the permitting history of the source to determine if previous projects should be aggregated with the current project.

(1) Administrative Amendment No. 079-45452-00008 (issued on August 16, 2022)
Seeking approval to install Activated Carbon Injection (ACI) systems to control mercury emissions from two (2) pulverized coal-fired boilers identified as Unit 17 and Unit 18.

(2) Minor Source Modification No. 079-43419-00008 (issued on December 7, 2020)
Seeking approval to install a natural gas-fired temporary boiler, with a maximum heat capacity of less than or equal to 99.9 MMBtu per hour.

(3) Administrative Amendment No. 079-43478-00008 (issued on December 7, 2022)
Seeking approval to install a natural gas-fired temporary boiler, with a maximum heat capacity of less than or equal to 99.9 MMBtu per hour.

Each project was approved internally as a standalone project. The financial justification for the capital approval for each project was not dependent on any other past, present, or future capital projects at Northern Indiana Public Service Company LLC, R.M. Schahfer Station. Therefore, these separate projects will have no impact on one another from an operational or utilization standpoint.

Permit Level Determination – Part 70 Modification to an Existing Source

Pursuant to 326 IAC 2-1.1-1(12), Potential to Emit is defined as “the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical

or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	PTE Before Controls of the New Emission Units (ton/year)								
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[2]**	**Total HAPs**
Turbines 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	12.09	15.96
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	4.82	10.82
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	0.004	0.008
Emergency Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.001	0.002
Total PTE Before Controls of the New Emission Units:	**124.49**	**124.69**	**124.68**	**33.94**	**1206.60**	**135.83**	**1169.94**	**16.91**	**26.79**

[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[2]Single highest HAP (Formaldehyde).

Appendix A of this TSD reflects the detailed potential emissions of the modification.

(a) Approval to Construct

Pursuant to 326 IAC 2-7-10.5(g)(2), a Significant Source Modification is required because this modification is subject to 326 IAC 8-1-6.

Pursuant to 326 IAC 2-7-10.5(g)(4), a Significant Source Modification is required because this modification has the potential to emit PM/PM10/direct PM2.5, sulfur dioxide (SO2), nitrogen oxides (NOx), VOC at equal to or greater than twenty-five (25) tons per year.

Pursuant to 326 IAC 2-7-10.5(g)(6), a Significant Source Modification is required because this modification has a potential to emit equal to or greater than ten (10) tons per year of a single HAP and twenty-five (25) tons per year of any combination of HAPs.

Pursuant to 326 IAC 2-7-10.5(g)(7), a Significant Source Modification is required because this modification has a potential to emit equal to or greater than one hundred (100) tons per year of carbon monoxide (CO).

(b) Approval to Operate

Pursuant to 326 IAC 2-7-12(d)(1), this change to the permit is being made through a Significant Permit Modification because this modification does not qualify as a Minor Permit Modification or as an Administrative Amendment.

Permit Level Determination – PSD Emissions Increase

(a) Actual to Potential (ATP) Applicability Test
Since this project only involves the construction of new emissions units and/or emissions units considered new for this evaluation, an Actual to Potential (ATP) applicability test, specified in 326 IAC 2-2-2(d)(4), is used to determine if the project results in a Significant Emissions Increase.

(b) New Emissions Units Only
Pursuant to 326 IAC 2-2-1(t)(1), a new emissions unit is any emissions unit that is, or will be, newly constructed and that has existed for less than two (2) years from the date the emissions unit first operated.

The following proposed emissions unit(s) are considered as new emissions units for this evaluation.

(1) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, each with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

(2) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

(3) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

(4) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

(c) Baseline Actual Emissions
New Emissions Unit(s)
For a new emissions unit, the baseline actual emissions for purposes of determining the Emissions Increase that will result from the initial construction and operation of the unit shall equal zero (0) and thereafter, for all other purposes, shall equal the unit's potential to emit.

(d) Actual to Potential (ATP) Summary
An Actual to Potential (ATP) applicability test has been conducted the new emissions units and/or the emissions units considered new for this evaluation.

$ATP_{(new\ unit)} = PTE_{(new\ unit)} - Baseline\ Emissions_{(new\ unit)}$

See Appendix A of this Technical Support Document for detailed emission calculations.

New Emissions Units ATP (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Turbines 19A, 19B, 19C (ATP)	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Turbine 20 (ATP)	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Emergency Generator EDG1 (ATP)	0.24	0.29	0.28	0.01	7.96	1.54	4.20

New Emissions Units ATP (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Emergency Fire Pump FP1 (ATP)	0.03	0.18	0.18	0.17	0.54	0.11	0.47
Total	**61.31**	**124.69**	**124.68**	**33.94**	**1206.60**	**81.35**	**1169.94**
Significant Levels	25	15	10	40	40	40	100

The project emissions for PM, PM_{10}, $PM_{2.5,}$ NOx, VOC, and CO are each above the applicable PSD significant thresholds. Therefore, the project is a significant emissions increase for PM, PM_{10}, $PM_{2.5,}$ NOx, VOC, and CO.

The source performed a netting analysis, specified in 326 IAC 2-2-2(d)(1) and (d)(2), to demonstrate that the modification is not subject to PSD major review for the project PM, PM10, PM2.5, NOx, VOC, and CO emissions.

(e) Netting Applicability Test

The source performed a netting analysis, specified in 326 IAC 2-2-2(d)(1) and (d)(2), to demonstrate that the modification is not subject to PSD major review for the project PM, PM_{10}, $PM_{2.5,}$ NOx, VOC, and CO emissions.

For this netting analysis, the source has considered the project emissions increases described above (see ATP Summary), and identified contemporaneous increases and decreases associated with this project:

(f) Contemporaneous Emissions Decreases

The following emissions decreases are contemporanous with the proposed modification.

(1) One (1) cyclone coal-fired boiler, identified as Unit 14, with construction commenced in 1970 and commercial operation begun in 1976, with a design heat input capacity of 4,650 million Btu per hour (MMBtu/hr), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an activated carbon, Amended Silicates, or equivalent system for control of mercury emissions authorized in 2014, and an electrostatic precipitator (ESP) exhausting to stack 14. Unit 14 has a selective catalytic reduction (SCR) system, a reagent injection system, a flue gas desulfurization system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM).

(2) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NOX burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an activated carbon, Amended Silicates, or equivalent system for control of mercury emissions authorized in 2014, and an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has a selective non-catalytic reduction (SNCR) system, a reagent injection system, a flue gas desulfurization system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM).

Note: Unit 14 was shut down in July 2020 and removed from the permit in November 2023. Unit 15 was shut down in September 2021 and removed from the permit in November 2023. The period between the shutdown of Units 14 and 15 and the construction and operation of the new units (Turbines 19A, 19B, 19C, and 20, Engine EDG1, and Fire Pump FP1) will be within the contemporaneous period. Therefore, emissions decrease for PM, PM10, PM2.5, NOx, VOC, and CO due to the shutdown of Units 14 and 15 will accounted for in this project.

(g) Contemporaneous Emissions Increases
The following emissions increases are contemporanous with the proposed modification.

(1) One (1) natural gas-fired temporary boiler, constructed in 2020, with a maximum capacity of less than or equal to 99.9 MMBtu per hour, using no control, and exhausting outdoors.

New Emissions Units ATP (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Project Emissions	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94

Contemporaneous Decreases (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Cyclone coal-fired boiler (Unit 14) and dry bottom pulverized coal-fired boiler (Unit 15)							
Baseline Actual Emissions	102.30	400.91	361.89	310.73	2166.44	82.31	4834.98
BAE	**-102.30**	**-400.91**	**-361.89**	**-310.73**	**-2166.44**	**-82.31**	**-4834.98**

Contemporaneous Increases (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Natural gas-fired temporary boiler installed in 2020							
Actual Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17
Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17

Net Emissions Increase (tons/year) "Project Emissions Accounting Test"							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**
ATP for New Emissions Units	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94
Contemporaneous Increases	0.11	0.44	0.44	N/A	2.13	0.32	2.17
Contemporaneous Decreases	-102.30	-400.91	-361.89	N/A	-2166.44	-82.31	-4834.98
Project Net Emissions Increase	**-40.88**	**-275.77**	**-236.77**	**33.94**	**-957.71**	**-0.65**	**-3662.87**
Significant Levels	25	15	10	40	40	40	100
*PM2.5 listed is direct PM2.5.							

The source has opted to take limits in order to render the requirements of 326 IAC 2-2 not applicable to this modification.

See Technical Support Document (TSD) State Rule Applicability - Entire Source section, 326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset) applicability determination for more information regarding the limits.

(h) Conclusion
The Permittee has provided information as part of the application for this approval that based on net emissions increases test in 326 IAC 2-2-2 this modification to an existing major PSD stationary source will not be major because the Net Emissions Increase of each PSD regulated pollutant is less than the PSD significant levels levels (SO_2 emissions increases from the project

only is less than the significant emission rate)(i.e., the modification does not cause a Significant Net Emissions Increase).

PTE of the Entire Source After Issuance of the Part 70 Modification

The table below summarizes the after issuance source-wide potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of the Part 70 source and/or permit modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions After Issuance (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[3]**	**Total HAPs**
Total PTE of Entire Source Including Fugitives*	1129	32162	32160	190203	23004	184	2206	1896	2454
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."

[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.

[3]Single highest source-wide HAP (HCl)

*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing major PSD stationary source will continue to be major under 326 IAC 2-2 because at least one pollutant, PM, PM10, PM2.5, SO2, NOx, VOC, and CO has emissions equal to or greater than the PSD major source threshold.

(b) The facility is a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for any single HAP and/or equal to or greater than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA). However, the Permittee has announced retirement dates for the two coal-fired boilers at the facility as end of 2025. Startup of the new combustion turbines authorized in 2024 will occur after the retirement date of the two coal-fired boilers (Unit 17 and Unit 18). Therefore, the Permittee has requested enforceable limitations to be imposed on the entire source after the retirement of Unit 17 and Unit 18 but prior to the startup of the new combustion turbines authorized for construction in 2024. These emission limitations will restrict single HAP emission below ten (10) TPY and all HAPs emissions to less than twenty-five (25) TPY making this an area source of HAPs.

Federal Rule Applicability Determination

Due to the modification at this source, federal rule applicability has been reviewed as follows:

New Source Performance Standards (NSPS):

(a) The requirements of the New Source Performance Standard for Stationary Gas Turbines, 40 CFR 60, Subpart GG and 326 IAC 12, are not included in the permit for the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, because they are subject to 40 CFR 60, Subpart KKKK.

(b) The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the New Source Performance Standards for Stationary Combustion Turbines 40 CFR 60, Subpart KKKK and 326 IAC 12, because each of these gas turbines has a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour and they will be constructed after February 18, 2005.

The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 are subject to the following portions of Subpart KKKK.

(1) 40 CFR 60.4305
(2) 40 CFR 60.4315
(3) 40 CFR 60.4320(a)
(4) 40 CFR 60.4330(a)
(5) 40 CFR 60.4333
(6) 40 CFR 60.4340
(7) 40 CFR 60.4345
(8) 40 CFR 60.4350
(9) 40 CFR 60.4355
(10) 40 CFR 60.4365
(11) 40 CFR 60.4370(b)
(12) 40 CFR 60.4375
(13) 40 CFR 60.4380
(14) 40 CFR 60.4395
(15) 40 CFR 60.4400
(16) 40 CFR 60.4405
(17) 40 CFR 60.4410
(18) 40 CFR 60.4420
(19) Table 1 to Subpart KKKK of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, except as otherwise specified in 40 CFR 60, Subpart KKKK.

(c) The requirements of the New Source Performance Standard for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60, Subpart TTTT and 326 IAC 12, are not included in the permit for the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, because the construction of these turbines will commence after May 23, 2023.

(d) The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, 40 CFR 60, Subpart TTTTa and 326 IAC 12, because these units are stationary combustion turbines that will be constructed after May 23, 2023, each has base load rating greater than 250 MMBtu per hour of fossil fuel, and each serve generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the following portions of Subpart TTTTa.

(1) 40 CFR 60.5509a(a)
(2) 40 CFR 60.5515a
(3) 40 CFR 60.5520a
(4) 40 CFR 60.5525a
(5) 40 CFR 60.5535a
(6) 40 CFR 60.5550a
(7) 40 CFR 60.5555a

(8) 40 CFR 60.5560a
(9) 40 CFR 60.5565a
(10) 40 CFR 60.5580a
(11) Table 1 to Subpart TTTTa of Part 60
(12) Table 3 to Subpart TTTTa of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, except as otherwise specified in 40 CFR 60, Subpart TTTTa.

(e) The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 are subject to the New Source Performance Standards for 40 CFR 60, Subpart Stationary Compression Ignition Internal Combustion Engine and 326 IAC 12, because these units are stationary compression ignition (CI) internal combustion engines (ICE) and will commence construction after July 11, 2005.

The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 are subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)
(2) 40 CFR 60.4205(b) and (c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4208
(6) 40 CFR 60.4209
(7) 40 CFR 60.4211(a), (c), and (f)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b) and (c)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 2 to Subpart IIII of Part 60
(13) Table 5 to Subpart IIII of Part 60
(14) Table 8 to Subpart IIII of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 except as otherwise specified in 40 CFR 60, Subpart IIII.

(f) The requirements of the New Source Performance Standard for Stationary Spark Ignition Internal Combustion Engines, 40 CFR 60, Subpart JJJJ and 326 IAC 12, are not included in the permit for the diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1, because these units are not stationary spark ignition internal combustion engines. They are stationary compression ignition internal combustion engines.

(g) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit for this proposed modification.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because these engines are considered new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engines (RICE) at an area source of hazardous air pollutants (HAP) because the Permittee has requested that the permit include emission limitations that will restrict single HAP emission below 10 tons

per year for single and the total HAPs emissions to less than 25 tons per year making this source an area source of HAPs prior to the first compliance date of this regulation.
The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 will comply with following requirements of 40 CFR 63, Subpart ZZZZ.

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(c)
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(b) The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are not subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY, which is incorporated by reference as 326 IAC 20-90, because these combustion turbines will be located at an "area source" of HAPs as of the first compliance date of the rule. The Permittee has proposed that prior to the first compliance date, which is the start of operation, for the new combustion turbines approved in 2024 for construction, the existing coal fired boilers (Unit 17 and Unit 18) will be shutdown making the facility an area source of HAPs. In addition, the Permittee has requested that the permit include emission limitations that will restrict single HAP emission below 10 tons per year for single and the total HAPs emissions to less than 25 tons per year making this source an area source of HAPs. This permit includes an enforceable condition that the operation of any of the new combustion turbines approved in 2024 for construction shall not start prior to the date of retirement of both coal fired boiler (Unit 17 and Unit 18) and appropriate emission limitations for source-wide HAPs emissions.

(c) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 63, 326 IAC 14 and 326 IAC 20 included for this proposed modification.

Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

(c) Pursuant to 40 CFR 64.2(b)(1)(iii), Acid Rain requirements pursuant to Sections 404, 405, 406, 407(a), 407(b), or 410 of the Clean Air Act are exempt emission limitations or standards. Therefore, CAM was not evaluated for emission limitations or standards for SO_2 and NO_X under the Acid Rain Program.

(d) Pursuant to 40 CFR 64.3(d), if a continuous emission monitoring system (CEMS) is required pursuant to other federal or state authority, the owner or operator shall use the CEMS to satisfy the requirements of CAM according to the criteria contained in 40 CFR 64.3(d).

The requirements of 40 CFR Part 64, CAM, are not applicable to any of the new units as part of this modification, since the new units do not have control devices.

Cross-State Air Pollutant Rule (CSAPR):

The USEPA has enacted the Cross State Air Pollutant Rule (CSAPR) which has replaced the Clean Air Interstate Rule (CAIR) effective January 1, 2015. Therefore, the Clean Air Interstate Rule (CAIR) expired on December 31, 2014. The Indiana Department of Environmental Management (IDEM) adopted the CAIR rule as State rule, 326 IAC 24-3. The Clean Air Interstate Rule (CAIR) Sulfur Dioxide Trading Program rule (326 IAC 24-2) and the Nitrogen Oxides Annual Trading Program (326 IAC 24-1) were repealed October 25, 2017. The final rule, The Clean Air Interstate Rule (CAIR) NOx Ozone Season Trading Program (326 IAC 24-3), was repealed on July 27, 2018. Therefore, The Clean Air Interstate Rule requirements have been removed from Section H and replaced with the requirements of 326 IAC 24 (Cross-State Air Pollution Rule (CSAPR) Programs)).

The preamble of the CSAPR regulations promulgated on August 8, 2011, states that the requirements established in the CSAPR trading program are applicable requirements that must be included in a source Title V permit pursuant to 40 CFR Part 70 and 71. The requirements of the Cross State Air Pollution Rules (CSAPR) apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and frame-type natural gas-fired combustion turbine, identified as Unit 20.

Transport Rule (TR) Trading Program Title V Requirements

The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and the frame-type natural gas-fired combustion turbine, identified as Unit 20, are subject to the requirements for the TR NOx Annual Trading Program, the TR NOx Ozone Season Trading Program, and the TR SO2 Group 1 Trading Program. The following tables summarize the unit specific monitoring provisions for this source:

Unit ID: 19A, 16B, 19C, and Unit 20					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	x	-------	-------	-------
NO_X	x	-------	-------	-------	-------
Heat input	-------	x	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2

Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

Cross-State Air Pollutant Rule (CSAPR):
The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and frame-type natural gas-fired combustion turbine, identified as Unit 20, are subject to the requirement of 326 IAC 21 which is incorporates the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements.

State Rule Applicability - Entire Source

Due to this modification, state rule applicability has been reviewed as follows:

326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset)
PSD and Emission Offset applicability is discussed under the Permit Level Determination – PSD and Emission Offset section and the Permit Level Determination - PSD Emissions Increase and the Permit Level Determination - Emission Offset Emissions Increase section of this document. The source is located in an area that is either designated as attainment or unclassifiable for all pollutants. Therefore, Emission Offset provisions do not apply.

2024 Modification

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits, shall limit the potential to emit of PM and VOC to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))

The provisions of 326 IAC 2-4.1 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997, unless the major source has been specifically regulated under or exempted from regulation under a NESHAP that was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act (CAA) and incorporated under 40 CFR 63. On and after June 29, 1998, 326 IAC 2-4.1 is intended to implement the requirements of Section 112(g)(2)(B) of the Clean Air Act (CAA).

The operation of the new combustion turbines (Units 19A, 19B, 19C, Unit 20), diesel-fired emergency generator (EDG1), and diesel-fired emergency fire pump (FP1) (approved in 2024 for construction) will emit equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. This is because the entire source is limited to these levels by enforceable permit conditions. Therefore, 326 IAC 2-4.1 would not apply to the combustion turbines.

326 IAC 2-7-6(5) (Annual Compliance Certification)

The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

326 IAC 5-1 (Opacity Limitations)

This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1)

326 IAC 6-4 (Fugitive Dust Emissions Limitations)

Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)

This source is not subject to the requirements of 326 IAC 6-5, because the source has potential fugitive particulate emissions of less than twenty-five (25) tons per year.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
Pursuant to 326 IAC 6.5-1-1(a), this source (located in Jasper County) is not subject to the requirements of 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

326 IAC 6.8 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-1(a), this source (located in Jasper County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

326 IAC 6.8 (Lake County: Fugitive Particulate Matter)
Pursuant to 326 IAC 6.8-10-1, this source (located in Jasper County) is not subject to the requirements of 326 IAC 6.8-10 because it is not located in Lake County.

326 IAC 24 (Cross-State Air Pollution Rule (CSAPR) Programs)
The source is subject to 326 IAC 24, because the requirements of 40 CFR Part 70 and 71 (Cross-State Air Pollution Rule (CSAPR)) apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and frame-type natural gas-fired combustion turbine, identified as Unit 20. The requirements of Clean Air Interstate Rule (CAIR) have been repealed.

326 IAC 20 (Hazardous Air Pollutants)
Pursuant to SSM No. 073-47965-00008 and in order to render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA), upon permanent shutdown and decommission of the coal-fired boilers, identified as Unit 17 and Unit 18, and startup, as defined at 40 CFR 63.2, of the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, the Permittee shall comply with following limits:

(a) The combined total HAP emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and Emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined single HAP (formaldehyde) emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with these limits, combined with the potential to emit HAP from all other emission units at the source, shall limit the source-wide potential to emit single HAP to less than 10 tons per twelve (12) consecutive month period and the source-wide potential to emit total HAPs to less than 25 tons per twelve (12) consecutive month period, and shall render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA).

State Rule Applicability – Individual Facilities

Due to this modification, state rule applicability has been reviewed as follows:

Natural Gas-fired Simple Cycle Combustion Turbines 19A, 19B, 19C

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, are not subject to 326 IAC 6-2 because they are not indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, are exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, are not subject to 326 IAC 326 IAC 7-1.1 because each turbine has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each turbine has unlimited VOC potential emissions less than twenty-five (25) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

326 IAC 3-5 (Continuous Monitoring of Emissions)
Pursuant to 326 IAC 3-5-1(a), the requirements of 326 IAC 3-5 are applicable to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, because these turbines are required to perform continuous emission monitoring system(s) (CEMS) under 326 IAC 12 (40 CFR 60.334(b)).

Natural Gas-fired Simple Cycle Combustion Turbine Unit 20

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the frame-type natural gas-fired combustion turbine, identified as Unit 20, is not subject to 326 IAC 6-2 because it is not an indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The frame-type natural gas-fired combustion turbine, identified as Unit 20, is exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The frame-type natural gas-fired combustion turbine, identified as Unit 20, is not subject to 326 IAC 326 IAC 7-1.1 because its potential to emit (or limited potential to emit) of sulfur dioxide (SO2) are less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
The frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, is subject to the requirements of 326 IAC 8-1-6, because it was constructed after January 1, 1980, and its unlimited VOC potential emissions are equal to or greater than twenty-five (25) tons per year, and the frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, is not regulated by other rules in 326 IAC 8. Therefore, a Best Available Control Technology (BACT) analysis was required for the frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20 (see Appendix B of this TSD).

According to the BACT analysis contained in Appendix B of this TSD, IDEM, OAQ has determined that the following requirements represent BACT for the frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20:

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the frame-type natural gas-fired combustion turbine, identified as Unit 20, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the frame-type natural gas-fired combustion turbine, identified as Unit 20, since this unit is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

326 IAC 3-5 (Continuous Monitoring of Emissions)
Pursuant to 326 IAC 3-5-1(a), the requirements of 326 IAC 3-5 are applicable to the frame-type natural gas-fired combustion turbine, identified as Unit 20, because this unit is required to perform continuous emission monitoring system(s) (CEMS) under 326 IAC 12 (40 CFR 60.334(b)).

Diesel Emergency Generator EDG1 and Diesel Emergency Fire Pump FP1

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the diesel emergency generator EDG1 and the diesel emergency fire pump FP1 are not subject to 326 IAC 6-2 because they are not indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The diesel emergency generator EDG1 and the diesel emergency fire pump FP1 are exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The diesel emergency generator EDG1 and the diesel emergency fire pump FP1 are not subject to 326 IAC 326 IAC 7-1.1 because each unit has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the diesel emergency generator EDG1 and the diesel emergency fire pump FP1 were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each unit has unlimited VOC potential emissions less than twenty-five (25) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the diesel emergency generator EDG1 and the diesel emergency fire pump FP1, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the diesel emergency generator EDG1 and the diesel emergency fire pump FP1, since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to assure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

(a) The Compliance Determination Requirements applicable to this modification are as follows:

Testing Requirements:

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Testing or Date of Initial Valid Demonstration)**	**Pollutant/ Parameter**	**Frequency of Testing**	**Authority**
One (1) of Combustion Turbines Units 19A, 19B, and 19C	None	180*	NOx (45.90 lb/hr)	One-time	326 IAC 2-2-3 40 CFR 60, Subpart KKKK
			Formaldehyde (0.920 lb/hr)	One-time	326 IAC 2-4.1
Combustion Turbine Unit 20	None	180*	NOx (139.80 lb/hr)	One-time	326 IAC 2-2-3 40 CFR 60, Subpart KKKK
			Formaldehyde (1.10 lb/hr)	One-time	326 IAC 2-4.1
* No later than 180 days after startup of the emission unit or completion of the modification. Note: Testing should be during normal operation. Testing for these pollutants is not required during startup/shutdown events.					

Testing of the diesel emergency generator EDG1 and diesel emergency fire pump FP1 is not required because they are not required to comply with any applicable requirements.

Continuous Emissions Monitoring System (CEMS) Requirements:

Emission Unit	Type of Continuous Monitor (Pollutant Monitored)	Applicable Rule or Authority
Units 19A, 19B, 19C, and Unit 20	CEMS for NOx	326 IAC 3-5 326 IAC 2-7-6(1) & (6) 40 CFR 60, Subpart KKKK

Proposed Changes

As part of this permit approval, the permit may contain new or different permit conditions and some conditions from previously issued permits/approvals may have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes.

The following changes listed below are due to the proposed modification. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text (these changes may include Title I changes):

(1) Section A.2 has been updated to include the unit descriptions of the new units.

(2) Section D.0 has been added to the permit to include the HAPs limits for the entire source to be an area source of HAPs after the completion of this modification.

(3) Section D.13 has been added to the permit to outline the applicable requirements for the new combustion turbines.

(4) Sections E.6 and E.9 have been revised to include the applicable requirements for the new emergency generator (EDG1) and fire pump (PF1).

(5) Sections E.10, E.11, and E.12 have been revised to include the applicable requirements for the new combustion turbines Units 19A, 19B, 19C, and Unit 20.

(6) Section H has been revised to include the new combustion turbine Units 19A, 19B, 19C, and Unit 20.

(7) New reporting forms for the new combustion turbines (Units 19A, 19B, 19C, and Unit 20) have been added.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)]
[326 IAC 2-7-5(14)]

*****

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

*****

(~~d~~ **f**)

*****

(~~e~~ **g**)

*****

(~~f~~ **h**)

*****

(~~g~~ **i**)

(~~h~~ **j**)

(~~i~~ **k**)

*****

(~~j~~ **l**)

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

*****

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

Pursuant to SSM No. 073-47965-00008 and in order to render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA), prior to the startup, as defined at 40 CFR 63.2, of the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, the emergency generator EDG1, and emergency fire pump FP1, the Permittee shall comply with following:

(a) The combined total HAPs emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined single HAP (formaldehyde) emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump,

emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) The two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from service.

Compliance with these limits, combined with the potential to emit HAP from all other emission units at the source, shall limit the source-wide potential to emit single HAP to less than 10 tons per twelve (12) consecutive month period and the source-wide potential to emit total HAPs to less than 25 tons per twelve (12) consecutive month period, and shall render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA).

Compliance Determination Requirements

D.0.2 Compliance Determination for Combined Total HAP

In order to determine compliance with Condition D.0.1(a), the combined total HAP emissions from the entire source shall be determined using the following equation:

$$E_{THAP} = \sum_{i=1}^{12}\left(\sum_{n}\frac{EF_{n19} * HI_{19A} + EF_{n19} * HI_{19B} + EF_{n19} * HI_{19C} + EF_{nU20} * HI_{U20} + EF_{n16} * HI_{16A} + EF_{n16} * HI_{16B} + EF_{nTB} * NT_{TB} + EF_{n350FP} * DT_{350FP} + EF_{nFP1} * DT_{FP1} + EF_{nEDG1} * DT_{EDG1}}{2000}\right)$$

Where:

E_{THAP} = Combined total HAP emissions (tons/month)
HI_{19A} = Heat input from turbine Unit 19A (MMBtu/month)
HI_{19B} = Heat input from turbine Unit 19B (MMBtu/month)
HI_{19C} = Heat input from turbine Unit 19C (MMBtu/month)
HI_{U20} = Heat input from turbine Unit 20 (MMBtu/month)
HI_{16A} = Heat input from turbine Unit 16A (MMBtu/month)
HI_{16B} = Heat input from turbine Unit 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (gallons/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (gallons/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (gallons/month)
EF_{n19} = Emission factors (in lb/MMBtu) for every single HAP from Units 19A, 19B, and 19C
EF_{nU20} = Emission factors (in lb/MMBtu) for every single HAP from Unit 20
EF_{n16} = Emission factors (in lb/MMBtu) for every single HAP from Units 16A and 16B
EF_{nTB} = Emission factors (in lb/MMscf) for every single HAP from temporary boiler
EF_{n350FP} = Emission factors (in lb/gallon) for every single HAP from 350 HP diesel fire pump
EF_{nEDG1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency generator EDG1
EF_{nFP1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency fire pump FP1
i = Each calendar month within the twelve (12) consecutive month period
n = Every single HAP emitted by emission units included in the HAP limit

D.0.3 Compliance Determination for Combined Single HAP (Formaldehyde)

In order to determine compliance with Condition D.0.1(b), the combined single HAP (formaldehyde) emissions from the entire source shall be determined using the following equation:

$$\sum_{i=1}^{12} E_{Single\ HAP\ (Formaledyde)} = \frac{ER_{19} * HR_{19A} + ER_{19} * HR_{19B} + ER_{19} * HR_{19C} + ER_{U20} * HR_{U20} + EF_{16} * HI_{16A} + EF_{16} * HI_{16B} + EF_{TB} * NT_{TB} + EF_{350FP} * DT_{350FP} + EF_{FP1} * DT_{FP1} + EF_{EDG1} * DT_{EDG1}}{2000}$$

Where:

$E_{Single\ HAP\ (Formaldehyde)}$ = Single HAP (Formaldehyde) Emissions (tons/month)
ER_{19} = 0.920 lb/hr, emission rate for formaldehyde for turbines 19A, 19B, and 19C or value established in latest compliant stack test
ER_{U20} = 1.10 lb/hr, emission rate for formaldehyde for turbine Unit 20 or value established in latest compliant stack test
HR_{19A} = Number of operating hours per month for turbine 19A
HR_{19B} = Number of operating hours per month for turbine 19B
HR_{19C} = Number of operating hours per month for turbine 19C
HR_{U20} = Number of operating hours per month for turbine Unit 20
HI_{16A} = Heat input from turbine 16A (MMBtu/month)
HI_{16B} = Heat input from turbine 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (hp-hr/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (hp-hr/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (hp-hr/month)
EF_{16} = 7.10E-04 lb/MMBtu, formaldehyde emission factor from AP-42 (Chapter 3.1 - Table 3.1-3)
EF_{TB} = 7.50E-02 lb/MMscf, formaldehyde emission factor from AP-42 (Chapter 1.4 - Table 1.4-3)
EF_{350FP} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*
EF_{EDG1} = 5.52E-07 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.4 - Table 3.4-3)*
EF_{FP1} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*
i = Each calendar month within the twelve (12) consecutive month period
*** Emission Factors in lb/hp-hr were calculated as follows: EF (lb/MMBtu) x 7,000 (Btu/hp-hr) x (1 MMBtu / 1,000,000 Btu)**

D.0.4 Testing Requirements [326 IAC 2-1.1-11]

In order to demonstrate compliance with Condition D.0.1 and to verify the emission rates for formaldehyde, not later than 180 days after the startup of the following emission units, the Permittee shall perform formaldehyde testing as follows:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	Formaldehyde (0.920 lb/hr)	One time
Frame type combustion turbine	Unit 20	Formaldehyde (1.10 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.0.5 Record Keeping Requirement

(a) To document the compliance status with Conditions D.0.1, the Permittee shall maintain monthly records in accordance with (1) and (3) below. Records maintained for (1) and (3) shall be taken as stated below and shall be complete and sufficient to establish compliance with the combined HAPs and single HAP emission limits established in Conditions D.0.1:

(1) Monthly combined total HAP emissions as calculated using the equation in Condition D.0.2.

(2) Monthly combined single HAP (formaldehyde) emissions as calculated using the equation in Condition D.0.3.

(3) The dates of shutdown for each unit listed in Condition D.0.1(c).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.0.6 Reporting Requirements

A quarterly summary of the information to document the compliance status with D.0.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1(35).

*****

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.13.1 PSD Minor Limit for PM and VOC [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 157-47442-00044, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits shall limit the potential to emit PM and VOC to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008.

D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), the Permittee shall minimize VOC emissions from the frame-type natural gas-fired combustion turbine, identified as Unit 20, using the Best Available Control Technology (BACT), which has been determined to be the following:

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.13.3 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for Nox, not later than 180 days after the startup of the following emission units, the Permittee shall perform NOx testing on the following emission units:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	NOx (45.90 lb/hr)	One time
Frame type combustion turbine	Unit 20	NOx (139.80 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.13.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the natural gas-fired combustion turbines Units 19A, 19B, 19C, and 20, shall be calibrated, maintained, and operated for measuring NOx, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, Subpart KKKK.

D.13.5 Compliance determination for PM and VOC

(a) To determine the compliance status with Condition D.13.1(a), the following equation shall be used to determine combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20 using the equation shown below for each:

$$E_{PM} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{PM} =	Total PM emissions (tons/month) form the combustion turbine Units 19A, 19B, 19C, 20
ER_N =	4.90 lb/hr PM emission rate in normal operation for Units 19A, 19B, and 19C or 11.6 lb/hour PM emission rate in normal operation for Unit 20, or value established in latest stack tests
$ER_{(SU/SD)}$ =	4.90 lb/event, PM emission rate in startup/shutdown events for Units 19A, 19B, and 19C or 11.60 lb/event, PM emission rate in startup/shutdown events for Unit 20
Evt =	Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle
H =	Number of hours of normal operation for the month for Units 19A, 19B, 19C, and 20
i =	Each calendar month within the twelve (12) consecutive month period
n =	Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

(b) To determine the compliance status with Condition D.13.1(b), the following equation shall be used to determine the combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20:

$$E_{VOC} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{VOC} =	Total VOC emissions (tons/month) from the combustion turbine Units 19A, 19B, 19C, 20
ER_N =	5.40 lb/hr, VOC emission rate in normal operation for Units 19A, 19B, and 19C, or 6.50 lb/hr VOC emission rate in normal operation for Unit 20, or value established in latest stack test.

$ER_{(SU/SD)}$ = 1.40 lb/event, VOC emission rate in startup/shutdown events for Units 19A, 19B, and 19C, or 101.00 lb/event, VOC emission rate in startup/shutdown events for Unit 20

Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle

H = Number of hours of normal operation for the month for Units 19A, 19B, 19C, and 20

i = Each calendar month within the twelve (12) consecutive month period

n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.13.6 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.13.7 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Permittee shall record the output of the continuous monitoring system (lb/hr) and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligation with regard to the records required by this condition.

D.13.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.13.1, the Permittee shall maintain monthly records in accordance with (1) and (2) below. Records maintained for (1) and (2) shall be taken as stated below and shall be complete and

sufficient to establish compliance with the PM and VOC emission limits established in Condition D.13.1:

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.6(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13.6(b).

(b) The number of startup and shutdown events per month.

(c) The number of minutes for each startup event and each shutdown event.

(d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.13.9 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1 (35).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1 (35).

D.13.10 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.13.1 shall be submitted not later than thirty (30) days after the end of the quarter being

reported. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

*****

SECTION E.6 NSPS

Emissions Unit Description:

*****

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

*****

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

*****

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 60.4200(a)
(2) 40 CFR 60.4205(b) and (c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4208
(6) 40 CFR 60.4209
(7) 40 CFR 60.4211(a), (c), and (f)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b) and (c)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219

(12) Table 2 to Subpart IIII of Part 60
(13) Table 5 to Subpart IIII of Part 60
(14) Table 8 to Subpart IIII of Part 60

*****

SECTION E.9 NESHAP

Emissions Unit Description:

*****

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-89]

*****

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(c)(7)
(4) 40 CFR 63.6595(a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(c)
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)

*****

SECTION E.10 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.10.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart KKKK.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.10.2 New Source Performance Standards for Stationary Combustion Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart KKKK (included as Attachment I to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.4305
(2) 40 CFR 60.4315
(3) 40 CFR 60.4320(a)
(4) 40 CFR 60.4330(a)
(5) 40 CFR 60.4333
(6) 40 CFR 60.4340
(7) 40 CFR 60.4345
(8) 40 CFR 60.4350
(9) 40 CFR 60.4355

(10) 40 CFR 60.4365
(11) 40 CFR 60.4370(b)
(12) 40 CFR 60.4375
(13) 40 CFR 60.4380
(14) 40 CFR 60.4395
(15) 40 CFR 60.4400
(16) 40 CFR 60.4405
(17) 40 CFR 60.4410
(18) 40 CFR 60.4420
(19) Table 1 to Subpart KKKK of Part 60

*****

SECTION E.11 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.11.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart TTTTa.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart TTTTa (included as Attachment J to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.5509a(a)
(2) 40 CFR 60.5515a
(3) 40 CFR 60.5520a
(4) 40 CFR 60.5525a
(5) 40 CFR 60.5535a
(6) 40 CFR 60.5550a
(7) 40 CFR 60.5555a
(8) 40 CFR 60.5560a
(9) 40 CFR 60.5565a
(10) 40 CFR 60.5580a
(11) Table 1 to Subpart TTTTa of Part 60
(12) Table 3 to Subpart TTTTa of Part 60

*****

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)

ORIS Code: 994

*****

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

H.10 Description of TR Monitoring Provisions

*****

Unit ID: 19A, 16B, 19C, and Unit 20					
Parameter	**Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)**	**Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D**	**Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E**	**Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19**	**EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E**
SO_2	-------	**X**	-------	-------	-------
NO_X	**X**	-------	-------	-------	-------
Heat input	-------	**X**	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2

Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Emission Units: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: PM Emissions
Limit: Shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	PM Emissions (tons)	*PM Emissions (tons)*	*PM Emissions (tons)*
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Emission Units: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: VOC Emissions
Limit: Shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	VOC Emissions (tons)	*VOC Emissions (tons)*	*VOC Emissions (tons)*
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: **Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, Indiana 46392**
Part 70 Permit No.: **T 073-45762-00008**
Emission Units: **Source-wide**
Parameter: **Combined Total HAP Emissions**
Limit: **Shall be less than 25 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month**

QUARTER:_____ **YEAR:_____**

Month	Column 1	Column 2	Column 1 + Column 2
	Total HAP Emissions (tons)	*Total HAP Emissions (tons)*	*Total HAP Emissions (tons)*
	This Month	Previous 11 Months	12 Month Total

☐ **No deviation occurred in this quarter.**
☐ **Deviation/s occurred in this quarter.**
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Emission Units: Source-wide
Parameter: Combined Single HAP (Formaldehyde) Emissions
Limit: Shall be less than 10 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	Single HAP (Formaldehyde) Emissions (tons)	***Single HAP (Formaldehyde) Emissions (tons)***	***Single HAP (Formaldehyde) Emissions (tons)***
	This Month	**Previous 11 Months**	**12 Month Total**

☐ **No deviation occurred in this quarter.**
☐ **Deviation/s occurred in this quarter.**
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on June 17, 2024

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 073-47965-00008. The operation of this proposed modification shall be subject to the conditions of the attached proposed Significant Permit Modification No. 073-48085-00008.

The staff recommends to the Commissioner that the Part 70 Significant Source Modification and Significant Permit Modification be approved.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled Potential to Emit (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	69,589	16,006	16,006	95,079	9,383	46.91	390.95	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	69,589	16,006	16,006	95,079	9,383	46.91	390.95	3,768,728	1211.34	938.28	HCl
Turbine 16A	41.92	41.92	41.92	21.49	2,032	13.34	520.78	705,653	7.90	4.51	Formaldehyde
Turbine 16B	41.92	41.92	41.92	21.49	2,032	13.34	520.78	705,653	7.90	4.51	Formaldehyde
Turbine 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	--	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	--	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**139393**	**32227**	**32225**	**190236**	**24056**	**259**	**3010**	**9001592**	**2466**	**1877**	**HCl**

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Limited Potential to Emit (tons/year)

Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	GHGs	Total HAPs	Worst Single HAP	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	--	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	--	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**1129**	**32162**	**32160**	**190203**	**23004**	**184**	**2206**	**7912502**	**2454**	**1896**	**HCl**

Limited Potential to Emit After Removal of Boilers Unit 17 and Unit 18 (tons/year)

Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	GHGs	Total HAPs	Worst Single HAP	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	--	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	--	10.82	4.82	Formaldehyde
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**81.46**	**147.29**	**147.28**	**44.19**	**2153.22**	**90.02**	**1424.50**	**375045.75**	**<25**	**<10**	**Formaldehyde**

Appendix A: Emission Calculations
Modofication Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled PTE of New Units (ton/yr)										
	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	Total HAPs	Single HAPs	
Turbine 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	10.82	4.82	Formaldehyde
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	0.008	0.004	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.002	0.001	Benzene
Total	***124.49***	***124.69***	***124.68***	***33.94***	***1206.60***	***135.83***	***1169.94***	***26.79***	***16.91***	**Formaldehyde**

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Contemporaneous Emissions Decreases

Existing Emission Units (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Unit 14 and Unit 15							
Baseline Actual Emissions	102.30	400.91	361.89	310.73	2166.44	82.31	4834.98
Baseline period 2018-2019							
BAE	***-102.30***	***-400.91***	***-361.89***	***-310.73***	***-2166.44***	***-82.31***	***-4834.98***

Contemporaneous Emissions Increases

Emissions (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Temporary Boiler Operation							
Actual Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17
Period of emissions 2023							
BAE	***0.11***	***0.44***	***0.44***	***0.03***	***2.13***	***0.32***	***2.17***

New Emission Units (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C							
Potential Emissions	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*36.49*	*71.72*	*71.72*	*13.24*	*595.38*	*31.45*	*710.10*
ATP	***36.49***	***71.72***	***71.72***	***13.24***	***595.38***	***31.45***	***710.10***
Turbine 20							
Potential Emissions	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*24.56*	*52.50*	*52.50*	*20.52*	*602.99*	*48.25*	*455.17*
ATP	***24.56***	***52.50***	***52.50***	***20.52***	***602.99***	***48.25***	***455.17***
Emergency Generator EDG1							
Potential Emissions	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.24*	*0.29*	*0.28*	*0.01*	*7.69*	*1.54*	*4.20*
ATP	***0.24***	***0.29***	***0.28***	***0.01***	***7.69***	***1.54***	***4.20***
Emergency Fire Pump FP1							
Potential Emissions	0.03	0.18	0.18	0.17	0.54	0.11	0.47
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.03*	*0.18*	*0.18*	*0.17*	*0.54*	*0.11*	*0.47*
ATP	***0.03***	***0.18***	***0.18***	***0.17***	***0.54***	***0.11***	***0.47***

Grey Cells are limited emissions

New Emissions Units Potential to Emit (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Turbine 20	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Emergency Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47
ATP	***61.31***	***124.69***	***124.68***	***33.94***	***1206.60***	***81.35***	***1169.94***

Net Emissions Increase (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
ATP for New Emission Units	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94
Contemporaneous Increases	0.11	0.44	0.44	NA	2.13	0.32	2.17
Contemporaneous Decreases	-102.30	-400.91	-361.89	NA	-2166.44	-82.31	-4834.98
Net Emissions Increase	**-40.88**	**-275.77**	**-236.77**	**33.94**	**-957.71**	**-0.65**	**-3662.87**
Significance Threshold (tpy)	25	15	10	40	40	40	100

Unit 14 was shutdown in July 2020 and removed fom the permit in November 2023. Unit 15 was shutdown in September 2021 and removed from the permit in November 2023. The period between the shutdown/removal of Units 14 and 15 and the construction and operation of the new units (Turbines 19A, 19B, 19C, and 20, Engine EDG1, and Fire Pump FP1) will be within the contemporaneous peride. Therefore, emissions decrease for

PM and VOC should be subject to the 40% capacity factor limited to avoid being subject to PSD BACT analysis

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
99.9	1020	858.0

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	37.1 **see below	5.5	37.7
Potential Emission in tons/yr	0.82	3.26	3.26	0.26	15.92	2.36	16.17

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.50E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	9.0E-04	5.1E-04	3.2E-02	0.77	1.5E-03	**0.81**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	2.1E-04	4.7E-04	6.0E-04	1.6E-04	9.0E-04	**2.4E-03**
Methodology is the same as above.					**Total HAPs**	**0.81**
The five highest organic and metal HAPs emission factors are provided above.					**Worst HAP**	**0.77**
Additional HAPs emission factors are available in AP-42, Chapter 1.4.						

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	51,478	0.99	0.94
Summed Potential Emissions in tons/yr	51,480		
CO2e Total in tons/yr	51,784		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #17

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %		Weight %
Sulfur =	3.2	Ash =	8.90

Uncontrolled PTE	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*				*10,425*		

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 17.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1yr * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #18

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)	Potential Throughput (ton/hr)
3967	11111	1.56E+06	1.79E+02

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Uncontrolled PTE

	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*	--	--	--	*10,425*	--	--

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 18.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1year * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/22)

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of C	Potential Throughput (ton/yr)
3967	11111	1560000

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Limited

	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7 (10A)	20.47 (2.3A)	3.6 *(38S)*	4.4	0.06	6.00
Potential Emission in tons/yr	524	16,006	2,852	3,475	47	4,691

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A: Emission Calculations
Natural Gas Combustion Only
Turbine 16A

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450.0	1020	12452.9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41.92	41.92	41.92	21.49	2032.32	13.34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Uncontrolled Emission Factor in lb/MMBtu * 2000hours/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1.2E-05	4.3E-07	7.10E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4.06E-01	8.26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4.0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8.26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O
Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 200hours/yr /2000lb/ton

Appendix A: Emission Calculations
Natural Gas Combustion Only
Turbine 16B

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450.0	1020	12452.9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41.92	41.92	41.92	21.49	2032.32	13.34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor in lb/MMBtu * 2000hrs/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1.2E-05	4.3E-07	7.1E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4.06E-01	8.26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4.0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8.26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/yr * 1ton/2,000 lb
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 2000hours/1 year * 1ton/2000lbs

Appendix A: Emissions Calculations
Turbines 19A, 19B, and 19C

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation

Maximum Heat input per Turbine	519	MMBtu/hr
Output (gross)	55	MW
Number of Turbines:	3	
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)
Number of SU/SD	4	events per day
CT operation	1,460	events/year
Startup duration for CT*	0.17	hour
Shutdown duration for CT**	0.15	hour
Heat input during events***	73.60	MMBtu/event
Worst case sulfur in NG	0.50	gr/100 cf
SO2 emission factor	0.002	lb/MMBtu

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 turbines)
PM	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM10	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM2.5	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	12.92 tons/yr	0.32 tons/yr	13.24 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	571.29 tons/yr	24.09 tons/yr	595.38 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	67.21 tons/yr	3.07 tons/yr	70.28 tons/yr
CO	50.70 lb/hr	36.10 lb/event	631.04 tons/yr	79.06 tons/yr	710.10 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 Turbines)
PM	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
PM10	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
PM2.5	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	5.46 tons/yr	0.32 tons/yr	5.78 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	241.25 tons/yr	24.09 tons/yr	265.34 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	28.38 tons/yr	3.07 tons/yr	31.45 tons/yr
CO	50.70 lb/hr	36.10 lb/event	266.48 tons/yr	79.06 tons/yr	345.54 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors	***Unlimited HAP Emissions***	***Limited HAP Emissions***	
Hexane	2.50E-04 lb/MMBtu	1.70 tons/yr	0.68 tons/yr	
1,3-Butadiene	4.3E-07 lb/MMBtu	0.00 tons/yr	0.00 tons/yr	
Acetaldehyde	4.00E-05 lb/MMBtu	0.27 tons/yr	0.11 tons/yr	
Acrolein	6.40E-06 lb/MMBtu	0.04 tons/yr	0.02 tons/yr	
Benzene	1.20E-05 lb/MMBtu	0.08 tons/yr	0.03 tons/yr	
Ethylbenzene	3.20E-05 lb/MMBtu	0.22 tons/yr	0.09 tons/yr	
Formaledyhyde	0.920 lb/hr	12.09 tons/yr	4.84 tons/yr	
Napathalene	1.30E-06 lb/MMBtu	0.01 tons/yr	0.00 tons/yr	
PAH	2.20E-06 lb/MMBtu	0.02 tons/yr	0.01 tons/yr	
Proplene Oxide	2.90E-05 lb/MMBtu	0.20 tons/yr	0.08 tons/yr	
Toluene	1.30E-04 lb/MMBtu	0.89 tons/yr	0.35 tons/yr	
Xylene	6.40E-05 lb/MMBtu	0.44 tons/yr	0.17 tons/yr	
	Total HAP Emissions	**15.96 tons/yr**	**6.38 tons/yr**	
	Single Worst HAP Emission	**12.09 tons/yr**	**4.84 tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) 1.77E-03
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Appendix A: Emissions Calculations
Turbine 20

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation

Maximum Heat input per Turbine	2416	MMBtu/hr
Output (gross)	247	MW
Number of Turbines:	1	
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)
Number of SU/SD	2	events per day
CT operation	730	events/year
Startup duration for CT	0.35	hour
Shutdown duration for CT	0.25	hour
Heat input during events	564	MMBtu/event
Worst case sulfur in NG	0.50	gr/100 cf
SO2 emission factor	0.002	lb/MMBtu

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
PM10	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
PM2.5	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	20.11 tons/yr	0.41 tons/yr	20.52 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	581.71 tons/yr	21.28 tons/yr	602.99 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	27.05 tons/yr	36.87 tons/yr	63.91 tons/yr
CO	51.10 lb/hr	664.50 lb/event	212.63 tons/yr	242.54 tons/yr	455.17 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
PM10	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
PM2.5	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	8.47 tons/yr	0.41 tons/yr	8.88 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	244.93 tons/yr	21.28 tons/yr	266.21 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	11.39 tons/yr	36.87 tons/yr	48.25 tons/yr
CO	51.10 lb/hr	664.50 lb/event	89.53 tons/yr	242.54 tons/yr	332.07 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors	***Unlimited HAP Emissions***	***Limited HAP Emissions***	
Hexane	2.50E-04 lb/MMBtu	2.65 tons/yr	1.06 tons/yr	
1,3-Butadiene	4.3E-07 lb/MMBtu	0.00 tons/yr	0.00 tons/yr	
Acetaldehyde	4.00E-05 lb/MMBtu	0.42 tons/yr	0.17 tons/yr	
Acrolein	6.40E-06 lb/MMBtu	0.07 tons/yr	0.03 tons/yr	
Benzene	1.20E-05 lb/MMBtu	0.13 tons/yr	0.05 tons/yr	
Ethylbenzene	3.20E-05 lb/MMBtu	0.34 tons/yr	0.14 tons/yr	
Formaledyhyde	1.10 lb/hr	4.82 tons/yr	1.93 tons/yr	
Napathalene	1.30E-06 lb/MMBtu	0.01 tons/yr	0.01 tons/yr	
PAH	2.20E-06 lb/MMBtu	0.02 tons/yr	0.01 tons/yr	
Proplene Oxide	2.90E-05 lb/MMBtu	0.31 tons/yr	0.12 tons/yr	
Toluene	1.30E-04 lb/MMBtu	1.38 tons/yr	0.55 tons/yr	
Xylene	6.40E-05 lb/MMBtu	0.68 tons/yr	0.27 tons/yr	
	Total HAP Emissions	**10.82 tons/yr**	**4.33 tons/yr**	
	Single Worst HAP Emission	**4.82 tons/yr**	**1.93 tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) 4.55E-04
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Appendix A: Emission Calculations
Gypsum Material Handling System
Radial Stackers

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Parameter		Value	Units	Source / Basis
New stacker throughput capacity	=	220	tons/hour	For each stacker. Information from the S&L Study 3-29-2012
New maximum throughput per stacker	=	1,927,200	tons/year	Based on 8,760 hours/year
Number of Stackers for Replacement	=	2		
Number of drop pont per stacker	=	1	Number	One drop point from stacker to pile
Moisture Content (M)	=	4.80	%	Conservative estimate
Annual Mean Wind speed (U)	=	10.00	mph	From RMS Calculations for Material Handling Emissions
PM Particle size multiplier (kP)	=	0.740	dimensionl	Ref. 1
PM10 Particle size multiplier (kP)	=	0.350	dimensionl	Ref. 1
PM2.5 Particle size multiplier (kP)	=	0.053	dimensionl	Ref. 1
PM Emission Factor	=	0.00171	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM10 Emission Factor	=	0.00081	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM2.5 Emission Factor	=	0.00012	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1

PTE Calculation Results

	PTE (TPY)		
Emission Unit	PM	PM10	PM2.5
Stacker 7MX04G-RS	1.65	0.78	0.12
Stacker 8MX04G-RS	1.65	0.78	0.12
Total	3.30	1.56	0.24

References:
1. EPA AP-42 Chapter 13.2.4; 11/2006.

Methodology:

PM/PM10/PM2.5 PTE (TPY) = New maximum throughput per stacker (tons/year) * Emission Factor (lb/ton/drop) * 1ton/2000lbs

Appendix A: Emission Calculations
Unit 17 & Unit 18
Activated Carbon Injection Grid

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Parameter		Value	Units	Source / Basis
Unit 17 AC Throughput Annual	=	365	tons/year	Design basis[1]
Unit 18 AC Throughput Annual	=	365	tons/year	Design basis[1]
PM Emission Factor	=	100%	fraction	AC particles in the 15 to 25 micrometer range[2]
PM10 Emission Factor	=	100%	fraction	Assumed 100% fractures to PM10[3]
PM2.5 Emission Factor	=	100%	fraction	Assumes 100% fractures to PM2.5[3]
Control Efficiency	=	99.75%		Use of ESP & Wet Scrubber[4]

PTE Calculation Results

	PTE, Controlled					
	Unit 17 (TPY)			Unit 18 (TPY)		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
ACI Stack Emissions	0.91	0.91	0.91	0.91	0.91	0.91

[1] Design basis establishes injection rate of ~2,000 pounds per day per unit.

[2] Activated Carbon Injection for Mercury Control on Industrial Coal-Fired Boilers Richard Miller Vice President Business Development ADA Environmental Solutions Co-Chairman ICAC Mercury Committee.

[3] Conservative assumption as worst case scenario.

[4] ESP design efficincies approximately 99.5%. Conservatively assumed that wet scrubber will achieve 50% additional reduction.

Appendix A: Emission Calculations
Fugitive Dust Emissions - Unpaved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Unpaved Roads at Industrial Site
The following calculations determine the amount of emissions created by unpaved roads, based on 8,760 hours of use and AP-42, Ch 13.2.2 (11/2006).

Vehicle Information (provided by source)

Type	Maximum number of vehicles	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	264	0.050	0.0	2.6
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	264	0.050	0.0	2.6
		Totals	**0.3**		**6.6**			**0.0**	**5.1**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.05 miles/trip

Unmitigated Emission Factor, Ef = k*[(s/12)^a]*[(W/3)^b] (Equation 1a from AP-42 13.2.2)

	PM	PM10	PM2.5	
where k =	4.9	1.5	0.15	lb/mi = particle size multiplier (AP-42 Table 13.2.2-2 for Industrial Roads)
s =	4.8	6.0	6.0	% = mean % silt content of unpaved roads (AP-42 Table 13.2.2-1 Iron and Steel Production)
a =	0.7	0.9	0.9	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)
W =	23.5	23.5	23.5	tons = average vehicle weight
b =	0.45	0.45	0.45	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [(365 - P)/365] (Equation 2 from AP-42 13.2.2)
Mitigated Emission Factor, Eext = E * [(365 - P)/365]
where P = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.2-1)

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	6.51	2.03	0.20	lb/mile
Mitigated Emission Factor, Eext =	4.37	1.36	0.14	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.01**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Mitigated PTE (Before Control) (tons/yr) = (Maximum one-way miles (miles/yr)) * (Mitigated Emission Factor (lb/mile)) * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = (Mitigated PTE (Before Control) (tons/yr)) * (1 - Dust Control Efficiency)

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particulate Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Paved Roads at Industrial Site
The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	1056	0.200	0.0	10.2
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	1056	0.200	0.0	10.2
		Totals	**0.3**		**6.6**			**0.1**	**20.4**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.20 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	23.5	23.5	23.5	tons = average vehicle weight
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	2.177	0.435	0.1069	lb/mile
Mitigated Emission Factor, Eext =	1.998	0.400	0.0981	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.02**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (Before Control) (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = [Mitigated PTE (Before Control) (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

One (1) diesel fire pump 350 HP

Output Horsepower Rating (hp)	350.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	175,000

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.0022	0.0021	0.0310	0.0025	0.0067
Potential Emission in tons/yr	0.19	0.19	0.19	0.18	2.71	0.22	0.58

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.71E-04	2.51E-04	1.75E-04	2.39E-05	7.23E-04	4.70E-04	5.67E-05	1.03E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.37E-03**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Green House Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	1.01E+02	4.05E-03	8.10E-04

Summed Potential Emissions in tons/yr	**1.01E+02**
CO2e Total in tons/yr	**1.01E+02**

Methodology
Emission Factors are from AP42 (Supplement B 10/96), Tables 3.3-1 and 3.3-2
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)
Emergency Engine EDG1

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	2922.0	NSPS Subpart IIII Emission Standards based on a: 2007	model year emergency engine
Output Horsepower Rating (kw)	2178.9		
Maximum Hours Operated per Year	500	(emergency generator or fire pump)	
Potential Throughput (hp-hr/yr)	1,461,000		
Potential Throughput (kw-hr/yr)	1,089,468		
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))	

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2 *(.00809S)*	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		4.01E-04	3.89E-04	1.21E-05			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				6.40	1.28	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0.29	0.28	0.01			
Based on g/kw-hr Emission Factor	0.24				7.69	1.54	4.20
Potential Emission in tons/yr	**0.24**	**0.29**	**0.28**	**0.01**	**7.69**	**1.54**	**4.20**

*The PM10 and PM2.5 emission factors for are from AP-42 Table 3.4-2. The PM10 emission factor is the sum of filterable PM10 and condensable particulate. The PM2.5 emission factor is the sum of filterable particulate less than 3 um and condensable particulate. Emission factors in lb/hp-hr were calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	3.97E-03	1.44E-03	9.87E-04	4.03E-04	1.29E-04	4.03E-05	1.08E-03

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Potential Emission of Total HAPs (tons/yr)	**8.05E-03**	
Worste Single HAP	**3.97E-03**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.16E+00	6.35E-05	9.30E-06
Potential Emission in tons/yr	8.47E+02	4.64E-02	6.79E-03

Summed Potential Emissions in tons/yr	**8.47E+02**
CO2e Total in tons/yr	**8.51E+02**

Methodology
CO2 Emission Factor is from AP 42 (Supplement B 10/96) Table 3.4-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) based on 11/29/2013 federal GWPs= CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)
Fire Pump FP1

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

NSPS Subpart IIII Emission Standards based on a: 2009 model year emergency engine

Output Horsepower Rating (hp)	327.0	
Output Horsepower Rating (kw)	243.8	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	163,500	
Potential Throughput (kw-hr/yr)	121,922	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		0.0022	0.0022	0.00205			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				4.00	0.80	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0.18	0.18	0.17			
Based on g/kw-hr Emission Factor	0.03				0.54	0.11	0.47
Potential Emission in tons/yr	**0.03**	**0.18**	**0.18**	**0.17**	**0.54**	**0.11**	**0.47**

*PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.34E-04	2.34E-04	1.63E-04	2.24E-05	6.75E-04	4.39E-04	5.29E-05	9.61E-05

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.22E-03**
Worste Single HAP	**6.75E-04** Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.
Output Horsepower Rating (kw) = Output Horsepower Rating (hp) * (0.7457 kw/hp)
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Throughput (kw-hr/yr) = [Output Horsepower Rating (kw)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] * [ton/2,000 lbs]
Potential Emission (tons/yr) = [Potential Throughput (kw-hr/yr)] * [Emission Factor (g/kw-hr)] * [lb / 453.592 g] * [ton/2,000 lbs]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	9.40E+01	3.78E-03	7.57E-04

Summed Potential Emissions in tons/yr	**9.40E+01**
CO2e Total in tons/yr	**9.43E+01**

Methodology
CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential

Appendix A: Emission Calculations
Unit 14 & Unit 15 Actual Emissions

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Baseline Actual Emissions for Contemporaneous Changes

	2018 Emissions (ton/yr)		2019 Emissions (ton/yr)		BAE* (ton/yr)		Total
Pollutant	**Unit 14**	**Unit 15**	**Unit 14**	**Unit 15**	**Unit 14**	**Unit 15**	
PM	43.9	59.8	64.2	36.8	54.0	48.3	**102.3**
PM10	139.9	301.1	142.7	218.2	141.3	259.6	**400.9**
PM2.5	119.3	284.2	112.5	207.9	115.9	246.0	**361.9**
SO2	163.4	211.4	115.0	131.7	139.2	171.5	**310.7**
NOx	760.2	1,668.6	676.5	1,227.7	718.3	1448.1	**2166.4**
VOC	50.4	41.5	41.8	31.0	46.1	36.2	**82.3**
CO	232.8	5,262.4	192.4	3,982.3	212.6	4622.3	**4835.0**

* BAE: Baseline Actual Emissions

Emissions reported in the site emissions inventories

	2018	2019	
Unit 15 coal heat input	25,545,640	19,331,471	MMBtu
CO factor for Unit 15	0.41	lb/MMBtu	
CO stack test for Unit 15 - December 3, 2019			

	2018	2019	BAE	
Unit 15 CO emissions	5,262.4	3,982.3	4,622.3	TPY

Notes
PM, PM10, PM2.5 NOx, and VOC emissions from Unit 14 and Unit 15 and CO emissions from Unit 14, as reported to IDEM in the emissions inventories, during the 2018-19 period are selected as Baseline Actual Emissions (BAE).

A December 2019 CO stack test for Unit 15 demonstrates a CO emission rate of 0.41 lb/MMBtu of heat input to the unit. NIPSCO used the coal combustion heat input for 2018 and 2019 for Unit 15 and the CO emission factor from the stack test to estimate actual CO emissions as BAE for this unit.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: **NIPSCO - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-47965-00008**
Significant Permit Modification No: **073-48085-00008**
Reviewer: **Hachem Ismaili Alaoui**

Actual Throughput for year 2023

MMCF/yr
115.0

	Pollutant							
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO	CO2e
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	37.1 **see below	5.5	37.7	119,349
Potential Emission in tons/yr	0.11	0.44	0.44	0.03	2.13	0.32	2.17	6862.56

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.
CO2e from 40 CFR Part 98 Subpart A Table A-1 and Subpart C Tables C-1 and C-2.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Indiana Department of Environmental Management
Office of Air Quality

TSD Appendix B
Best Available Control Technology (BACT) Analysis Determination

Source Background and Description

Source Name:	**Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T073-45762-00008**
Operation Permit Issuance Date:	**November 13, 2023**
Significant Source Modification No.:	**073-47965-00008**
Significant Permit Modification No.:	**073-48085-00008**
Permit Reviewer:	**Hachem Ismaili Alaoui**

Background Information

Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station owns and operates a stationary electric utility generating station located at 2723 East 1500 North, Wheatfield, Indiana 46392. The source is currently operating under Part 70 Operating Permit Renewal No. T073-45762-00008, issued on November 13, 2023. This source is major under Prevention of Significant Deterioration (PSD) and a minor source of Hazardous Air Pollutants (HAPs) under Section 112 of the Clean Air Act.

Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station submitted an application on June 17, 2024 proposing to construct three (3) aero-derivative natural gas-fired simple cycle combustion turbines, one (1) frame-type natural gas-fired simple cycle combustion turbine, one (1) diesel emergency generator, and one (1) diesel emergency fire pump.

Requirement for Best Available Control Technology (BACT)

The requirements of 326 IAC 8-1-6 (New Facilities, General Reduction Requirements) applies to facilities located anywhere in the state that were constructed on or after January 1, 1980, which have potential volatile organic compounds (VOC) emissions greater than 25 tons per year, and which are not otherwise regulated by other provisions of 326 IAC 8 rule, and requires the reduction of VOC emissions using Best Available Control Technology (BACT).

The proposed one (1) frame-type natural gas-fired simple cycle combustion turbine has potential VOC emissions of greater than 25 tons per year and is therefore subject to this rule.

Pursuant to 326 IAC 8-1-6, the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), has performed the following Best Available Control Technology Review (BACT) review for the following frame-type natural gas-fired simple cycle combustion turbine:

(a) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, using no controls, and exhausting to stack 20.

Summary of the Best Available Control Technology (BACT) Process

IDEM, OAQ conducts BACT analyses in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

Also, in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, BACT analyses take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

VOC BACT: Frame-type Natural Gas-fired Simple Cycle Combustion Turbine (Unit 20) Determination

In combustion of natural gas in combustion turbines, VOC emissions occur as a result of incomplete combustion of carbon-based fuels. The primary factors influencing VOC formation are temperature and residence time within the high temperature environment of the combustor. Variations in fuel carbon content have relatively little effect on overall VOC emissions. Generally, the effect of the combustion zone temperature and residence time on VOC emissions generation is the opposite of their effect on NOx emissions generation. Higher combustion zone temperature and residence times lead to more complete combustion and lower VOC emissions, but higher NOx emissions. The formation of VOC emissions is also dependent on the loading of the turbine. A gas turbine operating under full load experiences greater fuel efficiency than lesser loads and reduces the generation of VOC emissions.

Two basic techniques for controlling VOC emissions from combustion turbines were discussed in this BACT: post-combustion control, which includes the installation of an oxidation catalyst to oxidize VOC to CO2 and good combustion practices.

Step One: Identify All Potentially Available Control Technologies

The following potentially available control technologies were identified for controlling VOC emissions from the reactor system:

(a) Oxidation Catalyst

Catalytic oxidation is an add-on control technology that is commonly used to reduce VOC emissions in conjunction with its target pollutant CO. The catalysts are typically made of a precious metal and operate at temperatures in a relatively narrow range of 650°F to 1,000°F. No reactant is used with an oxidation catalyst. As with CO, VOC compounds will react with residual O2 in the presence of a catalyst to form CO2 and water vapor. The performance of an oxidation catalyst system is dependent on the specific VOC constituents present in the combustion turbine exhaust. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, backpressure loss to the system, catalyst life, susceptibility to poisoning by fine particles in the exhaust gas which reduces the catalyst's effectiveness, and potential collateral increases in emissions of PM10 and sulfuric acid mist.

(b) Good combustion practices

Good combustion practices are a method of controlling VOC emissions from combustion turbines. Maintaining optimum combustion efficiency and/or implementing appropriate maintenance procedures are examples of good combustion practices.

Step Two: Eliminate Technically Infeasible Control Options

To be considered technically feasible, a control technology must either be successfully demonstrated on a unit or, if not demonstrated, then be "available and applicable". A technology is considered "available" if it can be obtained by the applicant through commercial channels. An available technology is considered "applicable" if it can reasonably be installed and operated on the unit in question.

The feasibility of each of the potentially applicable control options identified is evaluated below.

(a) Oxidation Catalyst

The frame-type simple cycle combustion turbine (Unit 20) has a potential VOC emission exceeds 25 tons per hour threshold. However, only 22% of the potential VOC emissions occur during the normal operation of the combustion turbines, where add-on an oxidation catalyst would be effective in reducing VOC emissions. Typically, oxidation catalyst systems are not effective at controlling VOC emissions from combustion turbines during startup or shutdown events as the exhaust temperature is outside the optimum operating range. The following table presents a conservative VOC cost effectiveness evaluation for the proposed frame-type combustion turbine for the purpose of BACT for use of oxidation catalyst. Detailed VOC BACT cost effectiveness calculations are included in Appendix C.

Parameter	Oxidation Catalyst
Total capital requirement	$7,900,000
Annual O&M cost	$33,000
Catalyst replacement annual coat	$32,571
Capital recovery annual cost	$581,296
Total annual cost	$646,867
Uncontrolled VOC emissions (tons/yr)	48.26
Controlled VOC emissions (tons/yr) Assumed VOC control efficiency of 90% for normal operation and 50% for SU/SD (conservative assumptions)	19.57
VOC control cost effectiveness (per ton of VOC)	$22,550

The capital cost associated with the installation of an oxidation catalyst on the frame-type combustion turbine is estimated to be $7.9 million. The capital cost of the oxidation catalyst system includes the catalyst housing, duct work, control systems and balance of plant equipment. An equipment life of 20 years and an interest rate of 4 percent are assumed resulting in a capital recovery factor of 0.07. The annual capital recovery cost is calculated as $581,296. The annual operating cost associated with the oxidation catalyst system is approximately $65,571 per year (Annual O&M cost + Catalyst replacement annual cost). The annual operating costs include catalyst replacement, energy impacts, operating personnel, and maintenance. A catalyst life of five years is assumed.

The resultant cost effectiveness associated with the use of the oxidation catalyst is $22,550 per ton of VOC controlled resulting in negative economic impacts. Installation of an oxidation catalyst will also have negative energy and environmental impacts as well. These will include increased pressure drop through the combustion turbine exhaust resulting in decreased electricity generation and disposal requirements of catalyst material. Based on the energy, environmental, and economic impacts, the installation of an oxidation catalyst is not a technically feasible option as VOC BACT for the proposed frame-type combustion turbine.

(b) Good combustion practices

Good combustion practices are essential for the operation and life-span of the proposed combustion turbine and will be implemented. The proposed combustion turbine will only combust natural gas as fuel. Therefore, good combustion practices and clean fuels are technically feasible for this combustion turbine. Among the natural gas-fired simple-cycle combustion turbines listed in the RBLC, the majority all listed natural gas-fired combustion turbines concluded that the use of good combustion practices was representative of BACT.

Step Three: Rank Feasible Technologies

The remaining technically feasible options for controlling VOC emissions from the reactor system are as follows (listed in descending order of most technically feasible):

(1) Oxidation Catalyst.

(2) Good combustion Practices.

Step Four: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 15.110 (Natural Gas Fired Large Simple Cycle Combustion Turbines – Peaking Units). The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number and Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO – R.M. Schahfer Generating Station	073-47965--00008	N/A	One (1) Frame-type Simple Cycle Combustion Turbine (Unit 20) (2,416 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 6.50 lb/hr during normal operation **Emission Limit 2:** 101.0 lb/event during startup 101.0 lb/event during shutdown
FPEC, LLC (Freestone Peakers Plant)	TX173582 June 13, 2024	TX-0975	Simple Cycle Gas Turbines (221.00 MW)	**Control Method:** Good combustion **Emission Limit 1:** 2.0 ppmvd @ 15% O2 **Emission Limit 2:** 0
Tenaska Roan's Prairie Partners (TRPP), LLC Roan's Prairie Generating Station	114698 PSDTX1378 September 22, 2014	TX-0696	Two Simple Cycle Turbines (600.00 MW)	**Control Method:** Good combustion practices **Emission Limit 1:** 1.4 ppmvd @ 15% O2 (For GE) **Emission Limit 2:** 1.0 ppmvd @ 15% O2 (for Siemens)

The capital cost associated with the installation of an oxidation catalyst on the frame-type combustion turbine is estimated to be $7.9 million. The cost effectiveness of this BACT option is over about $22,550 per ton VOC controlled. The recent BACT determinations for VOC in RBLC for natural gas-fired simple combustion turbines – peaking units utilize good combustion practices.

Step Five: Select BACT

Based on a review of the recent VOC BACT determinations for similar facilities and the cost analysis discussed in the above for the installation of an oxidation catalyst, IDEM has established the following as BACT for volatile organic compounds (VOC) for the proposed frame-type simple cycle combustion turbine (Unit 20):

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Ed Pierce
Northern Indiana Public Service Company LLC RM Schahfer Generating Station
2755 Raystone Dr
Valparaiso, IN 46383

DATE: February 4, 2025

FROM: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
TV Significant Permit Modification
073-48085-00008

This notice is to inform you that a final decision has been issued for the air permit application referenced above.

Our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person. In addition, the Notice of Decision has been sent to the OAQ Permits Branch Interested Parties List and, if applicable, the Consultant/Agent and/or Responsible Official/Authorized Individual.

The final decision and supporting materials are available electronically; the original signature page is enclosed for your convenience. The final decision and supporting materials available electronically at:

IDEM's online searchable database: https://www.in.gov/apps/idem/caats/ . Choose Search Option **by Permit Number**, then enter permit 48085

and

IDEM's Virtual File Cabinet (VFC): https://www.in.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, or have difficulty accessing the documents online, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Visit **on.IN.gov/survey** or scan the QR code to provide feedback.
We appreciate your input!

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

February 4, 2025

TO: Jasper County Public Library Wheatfield Public Library

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: **Northern Indiana Public Service Company LLC RM Schahfer Generating Station**
Permit Number: **073-48085-00008**

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library 1/13/2025

Visit **on.IN.gov/survey** or scan the QR code to provide feedback.
We appreciate your input!

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

February 4, 2025
Northern Indiana Public Service Company LLC RM Schahfer Generating Station
073-48085-00008

To: Interested Parties

This notice is to inform you that a final decision has been issued for the air permit application referenced above. This notice is for informational purposes only. You are not required to take any action.

You are receiving this notice because you asked to be on IDEM's notification list for this company and/or county; or because your property is nearby the company being permitted; or because you represent a local/regional government entity.

The enclosed Notice of Decision Letter provides additional information about the final permit decision.

The final decision and supporting materials are available electronically at:

IDEM's online searchable database: https://www.in.gov/apps/idem/caats/. Choose Search Option by Permit Number, then enter permit 48085

and

IDEM's Virtual File Cabinet (VFC): https://www.in.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit.

Please Note: *If you would like to be removed from the Air Permits mailing list, please contact Joanne Smiddie-Brush with the Air Permits Administration Section at 1-800-451-6027, ext. 3-0185 or via e-mail at JBRUSH@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
Final Interested Parties Cover Letter 1/13/2025

Mail Code 61-53

IDEM Staff	JLSCOTT 2/4/2025 Page 1 of 2 Northern Indiana Public Service Company LLC RM Schahfer Generating Station 073-48085-00008 Final		
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**

AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Ed Pierce Northern Indiana Public Service Company LLC RM Sch 2755 Raystone Dr Valparaiso IN 46383 (Source CAATS) via UPS									
2		Kurt Sangster Vice President of Operations Northern Indiana Public Service Company LLC RM Sch 2755 Raystone Dr Valparaiso IN 46383 *(RO CAATS)*									
3		Ms. Lana Gawronski 9296 N 900 W DeMotte IN 46310 *(Affected Party)*									
4		Mr. Aaron Webster 7149 W 1000 N DeMotte IN 46310 *(Affected Party)*									
5		The Echterling Residence 9180 W 950 N DeMotte IN 46310 *(Affected Party)*									
6		Current Resident 548 N Oak Dr Plymouth IN 46563 *(Affected Party)*									
7		Mr. Lawrence A Vanore Sommer & Barnard Ackerson 1 Indiana Square, Ste 3500 Indianapolis IN 46204-5198 *(Affected Party)*									
8		State Representative District 16 PO Box 1 Rensselaer IN 47978 *(Legislator)*									
9		Jasper County Commissioners 115 W Washington St Rensselaer IN 47978 *(Local Official)*									
10		Jasper County Health Department 910 S Sparling Ave #1 Rensselaer IN 47978-9132 *(Health Department)*									
11		Mr. Donald Speacht, Jr 11751 N CR 500 E San Pierre IN 46374 *(Affected Party)*									
12		The Banks Family 11846 N CR 100 E Wheatfield IN 46392 *(Affected Party)*									
13		Ms. Kay Asher 4036 Heritage Dr N Wheatfield IN 46392 (Affected Party)									
14		Ms. Maryann Desalvo 10145 N 200 E Wheatfield IN 46392 *(Affected Party)*									
15		Victor & Cleone Downing 1333 E 1225 N Wheatfield IN 46392 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

FACSIMILIE OF PS Form 3877

Mail Code 61-53

IDEM Staff	JLSCOTT 2/4/2025 Page 2 of 2 Northern Indiana Public Service Company LLC RM Schahfer Generating Station 073-48085-00008 Final		
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**

AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Deborah PO Box 307 Wheatfield IN 46392 (Affected Party)									
2		George & Joyce Gourko 2039 S 9th St Lafayette IN 47905 *(Affected Party)*									
3		Mr. Scott Helton PO Box 307 Wheatfield IN 46392 *(Affected Party)*									
4		Mr. Bob Hetrick 10274 N 200 E Wheatfield IN 46392 *(Affected Party)*									
5		Ms. Monica Jones 9250 N 100 W Wheatfield IN 46392 *(Affected Party)*									
6		Michael & Kathleen Teiron 4073 E 425 N Wheatfield IN 46392 *(Affected Party)*									
7		Robert & Barbara Witvoet 14240 N SR 49 Wheatfield IN 46392 *(Affected Party)*									
8		Sharon Williams 22745 Frederick Rd Steger IL 60475 *(Affected Party)*									
9		Darlene & Scott Holmes 9161 N 900 W Demotte IN 46310 *(Affected Party)*									
10		Mr. Kenny Haun PO Box 280 Rensselaer IN 47978 *(Affected Party)*									
11		Tom & Gail Clark 1186 E CR 1250 N Wheatfield IN 46392 *(Affected Party)*									
12		Wheatfield Town Council 170 S Grace St Wheatfield IN 46392 *(Local Official)*									
13		Jasper County Public Library - Wheatfield 350 S Bierma St Wheatfield IN 46392 (Library)									
14		Save the Dunes 444 Barker Rd Michigan City IN 46360 *(Affected Party)*									
15		La Porte County Herald-Dispatch 422 Franklin St, Ste B Michigan City IN 46360 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

FACSIMILIE OF PS Form 3877

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 102
MISO Attachment Y Response to NIPSCO

OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

NIPSCO
A NiSource Company

October 29, 2025

Martha Clark Mettler
Assistant Commissioner, Office of Water Quality
Indiana Department of Environmental Management
100 North Senate Avenue, 12th Floor
Indianapolis, IN 46204

RE: Northern Indiana Public Service Company
R. M. Schahfer Generating Station
NPDES Permit No. IN 0053201
Notice of Planned Participation under 40 CFR 423

Dear Ms. Clark Mettler:

This letter serves as Notice of Planned Participation under 40 CFR 423 – Effluent Limitations Guidelines (ELG) for the Electric Power Generating Point Source Category. Under the Reporting and Recordkeeping Requirements of 40 CFR 423.19(h), Northern Indiana Public Service Company, LLC (NIPSCO) is hereby notifying the permitting authority that absent a directive to remain open, NIPSCO plans to cease combustion at Units 17 and 18 at the R. M. Schahfer Generating Station by December 31, 2025, and qualify for the reduced requirements for combustion residual leachate (CRL) under the ELG Rule. This notice includes the following information, in accordance with 40 CFR 423.19(h)(2) – i.e., the 2034 subcategory:

Electric generating units intended to achieve the permanent cessation of coal combustion:

RESPONSE: Units 17 and 18 at NIPSCO's R. M. Schahfer Generating Station.

Expected date that each electric generating unit is projected to achieve permanent cessation of coal combustion:

RESPONSE: Absent a directive to remain open, NIPSCO remains on track to cease coal combustion at Schahfer's remaining two coal units by December 31, 2025.

Whether the date above represents a retirement or a fuel conversion:

RESPONSE: Retirement

Whether each retirement or fuel conversion has been approved by a regulatory body:

RESPONSE: On January 31, 2023, NIPSCO filed an Attachment Y Suspension Notice with the Midcontinent Independent System Operator (MISO) indicating retirement of Units 17 and 18 at R. M. Schahfer Generating Station by December 31, 2025. On February 3, 2023, MISO approved the Attachment Y Suspension Notice. This documentation is enclosed with this letter.

What the relevant regulatory body is:

RESPONSE: Midcontinent Independent System Operator (MISO).

Include a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs:

RESPONSE: In Indiana, utilities are required to submit Integrated Resource Plans (IRPs) to the Indiana Utility Regulatory Commission (IURC) every 3 years. While IRPs are submitted to the IURC as part of a legislative process, they are not regulatory filings where formal "approval" is granted. NIPSCO's 2024 IRP documents the planned retirement of Schahfer Units 17 and 18 by December 31, 2025.

Please see NIPSCO's 2024 IRP here:

https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf

Certification of electric generating unit (EGU) cessation under 40 CFR 257.103(b) or other documentation supporting that the EGU will permanently cease the combustion of coal by December 31, 2034:

RESPONSE: Please see the enclosed Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of Coal-Fired Boilers by a Date Certain Addendum 2 cover letter. Please also see the associated Addendum 2 report, filed with the U.S. Environmental Protection Agency pursuant to §257.103(f)(2) here:

https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-groundwater-moniitoring-and-corrective-action/rm-schahfer-generating-station-wda-part-a-addendum-2-summer-2022.pdf?sfvrsn=d2e31151_3

Timeline to achieve the permanent cessation of coal combustion (include interim milestones and the projected dates of completion):

RESPONSE:

January 31, 2023	Attachment Y Suspension Notice Submitted to MISO
February 3, 2023	Attachment Y Suspension Notice Approved by MISO
June 22, 2023	Submittal of Notice of Planned Participation under 40 CFR 423.19(g)
June 4, 2024	Annual Progress Report Submitted to the Indiana Department of Environmental Management (IDEM)
October 29, 2025	Annual Progress Report Submitted to the Indiana Department of Environmental Management (IDEM)
October 29, 2025	Submittal of Notice of Planned Participation under 40 CFR 423.19(h)
December 31, 2025	Absent a Directive to Remain Open, NIPSCO Remains On Track to Retire Schahfer's Remaining Two Coal Units By This Date

NIPSCO
A NiSource Company

Certification Statement that the facility is in compliance the applicable limitations or standards for FGD wastewater in 423.13(g) or (g)(2)(ii) or (iii) or 423.16(e)(1) or (2):

RESPONSE: NIPSCO is in compliance with all applicable limitations for FGD wastewater.

Certification Statement that the facility is in compliance the applicable limitations or standards for bottom ash transport water in 423.13(k)(1) or (k)(2)(i) or (iii) or 423.16(g)(1) or (2):

RESPONSE: NIPSCO is in compliance with all applicable limitations for bottom ash transport water.

If you have any questions or require additional information, please contact me at (219) 741-6742 or via email at sholcomb@nisource.com.

Sincerely,

Stephen Holcomb

Stephen Holcomb
Director, Environmental Policy and Sustainability

cc:
Scott Ireland, Director, U.S. EPA Region 5 Water Division
Paul Higginbotham, Deputy Assistant Commissioner, IDEM Office of Water Quality

Enclosures:
Attachment Y Suspension Notice
MISO's Approval of Attachment Y Suspension Notice
R. M. Schahfer Generating Station Demonstration Addendum Cover Letter Summer 2022

January 31, 2023

Andrew Witmeier
Director Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Dear Mr. Witmeier,

Pursuant to the discussions Northern Indiana Public Service Company LLC ("NIPSCO") had with MISO about moving suspension dates for Schahfer Units 17 and 18, please find enclosed new Attachment Y Notices for the suspension of Schahfer Units 17 and 18.

As shown on the Attachment Y Notices, NIPSCO is requesting a suspension date of December 31, 2025, instead of the currently approved date of May 31, 2023.

The following two individuals are the primary points of contact for NIPSCO:

Andrew S. Campbell
Director Portfolio Planning & Origination
NIPSCO
801 E. 86th Avenue
Merrillville, IN 46410
219.895.0771
andrewcampbell@nisource.com

M. Bryan Little
Assistant General Counsel
NiSource Corporate Services
150 West Market Street
Suite 600
Indianapolis, IN 46204
317.684.4903
blittle@nisource.com

Please let us know if you need any additional information.

Sincerely,

M. Bryan Little
Assistant General Counsel

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Northern Indiana Public Service Company LLC (NIPSCO)

Name of Market Participant: NIPSCO

Owner's state of organization or incorporation Indiana

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Schahfer Unit 17

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] The unit was interconnected to NIPSCO's transmission system prior to MISO

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[ ] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 31 [day] of December [month] of 2025 [year]

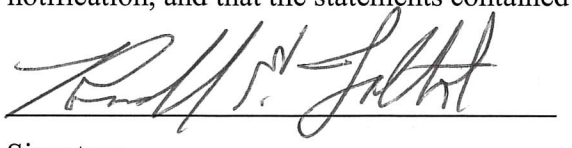
[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: 2723 E 1500 N Wheatfield, IN 46392

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Schahfer Unit 17	7NIPS.SCHAHP18	423.5	Retire All

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.



Signature

Name: Ronald E. Talbot

Contact Information

Title: SVP Electric Operations

Email: rtalbot@nisource.com

Date: 1/20/23

Phone: 219.647.5735

STATE OF Indiana

COUNTY OF Lake

Before me, the undersigned authority, this day appeared Ronald E. Talbot, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

"I am an officer of NIPSCO, I am authorized to execute and submit the foregoing notification on behalf of NIPSCO, and the statements contained in such application are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the 31 day of January, 2023

ALEXIS M CARTER
Notary Public - Seal
Porter County - State of Indiana
Commission Number NP0735519
My Commission Expires Aug 15, 2029

Alexis M Carter

Notary Public, State of INDIANA

My Commission expires Aug 15, 2029

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Northern Indiana Public Service Company LLC (NIPSCO)

Name of Market Participant: NIPSCO

Owner's state of organization or incorporation Indiana

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Schahfer Unit 18

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] The unit was interconnected to NIPSCO's transmission system prior to MISO

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[ ] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 31 [day] of December [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: 2723 E 1500 N Wheatfield, IN 46392

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Schahfer Unit 18	NIPS.SCHAHP18	423.5	Retire All

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: Ronald E. Talbot

Title: SVP Electric Operations

Date: 1/20/23

Contact Information

Email: rtalbot@nisource.com

Phone: 219.647.5735

STATE OF Indiana

COUNTY OF Lake

Before me, the undersigned authority, this day appeared Ronald E. Talbot, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

"I am an officer of NIPSCO, I am authorized to execute and submit the foregoing notification on behalf of NIPSCO, and the statements contained in such application are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the 31 day of January, 2023

ALEXIS M CARTER
Notary Public - Seal
Porter County - State of Indiana
Commission Number NP0735519
My Commission Expires Aug 15, 2029

Alexis M Carter

Notary Public, State of INDIANA

My Commission expires Aug 15, 2029

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA TWO-DAY-AIR DELIVERY

February 3, 2023

Ronald E. Talbot
Sr. VP Electric Operations
NIPSCO
801 E. 86th Avenue
Merrillville, IN 46410

Subject: **Approval of Schahfer Units 17 and 18 Attachment Y Suspension Notice**

Dear Mr. Talbot:

On February 1, 2023, Northern Indiana Public Service Company LLC submitted an amended Attachment Y Notice to MISO to move the suspension of Schahfer Units 17 and 18 from May 31, 2023 to December 31, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Schahfer Units 17 and 18 would not result in violations of applicable reliability criteria. Therefore, Schahfer Units 17 and 18 may suspend without the need for the generators to be designated as System Support Resource ("SSR") units as defined in the Tariff.

This letter acknowledges that Northern Indiana Public Service Company LLC will suspend Schahfer Units 17 and 18, effective December 31, 2025. MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

August 16, 2022

Submitted via email

Mr. Michael Regan, Administrator US EPA
1200 Pennsylvania Avenue, N.W.
Mail Code 5304-P
Washington, D.C. 20460

Re: Northern Indiana Public Service Company LLC
RM Schahfer Generating Station, Wheatfield, IN
Demonstration – Addendum 2, Pursuant to 40 CFR Part 257.103(f)(2)

Dear Administrator Regan:

Northern Indiana Public Service Company LLC (NIPSCO LLC) is providing the enclosed *Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of Coal-Fired Boilers by a Date Certain* Addendum 2 (Demonstration Addendum 2) for approval by the United States Environmental Protection Agency (US EPA). Approval of NIPSCO LLC's 257.103(f)(2) Demonstration by the US EPA will allow NIPSCO LLC to continue use of the Waste Disposal Area ash pond (WDA) in operation at the RM Schahfer Generating Station located in Wheatfield, IN (RMSGS, Site), after April 11, 20221. This approximately 80-acre pond will complete closure no later than October 17, 2028, as provided in the enclosed Demonstration Addendum #2.

This Demonstration Addendum 2, provides a new date of permanent cessation of coal-fired boilers at the RMSGS and NIPSCO's continued commitment to cease operation and complete closure the WDA no later than October 17, 2028, as stipulated in 257.103(f)(2)(iv)(B). Furthermore, to meet the requirements of 40 CFR § 257.103(f)(2), Demonstration Addendum 2 supplies information updated since November 2020 (i.e., the date Demonstration Addendum 1 was prepared) with respect to groundwater monitoring and corrective action activities at RMSGS.

As explained and justified herein, cessation of coal-fired generation at RMSGS will now be December 31, 2025, providing nearly three years to a) complete boiler shutdown processes, some of which are expected to generate significant volumes of CCR and non-CCR waste streams, b) reduce and/or eliminate other ongoing influent streams, c) optimize the closure plan and gain regulatory agency approval for the WDA closure approach, and d) complete closure construction. Following cease receipt

of WDA waste streams (Q2 2026), NIPSCO estimates a timeframe of approximately two and a half years to achieve final closure of the WDA including the professional engineer's certification, thereby achieving final closure by September 17, 2028, and meeting the 40 CFR § 257.103(f)(2) deadline of October 17, 2028.

This Demonstration Addendum 2 in combination with Demonstration (Golder, October 2020) and Demonstration Addendum 1 (Golder, November 2020) meet the requirements of 40 CFR § 257.103(f)(2).

Following US EPA guidance, the enclosed Demonstration Addendum 2 was submitted via email to Richard Huggins, Frank Behan, Kirsten Hillyer and Lydia Anderson. I may be contacted at (219) 680-8628 or mturman@nisource.com with questions or comments.

Sincerely,

Maureen Turman

Maureen Turman
NiSource Director Environmental Policy and Sustainability

Enclosure

CC: Richard Huggins, US EPA
Frank Behan, US EPA
Kirsten Hillyer, US EPA
Lydia Anderson, USEPA

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 103
NIPSCO 2019 Rate Order

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND, IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	CAUSE NO. 45159
	)	APPROVED: DEC 4 2019

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Stefanie N. Krevda, Commissioner
Brad J. Pope, Administrative Law Judge

On October 31, 2018, Northern Indiana Public Service Company LLC ("NIPSCO," "Petitioner," or "Company") filed its Verified Petition for General Rate Increase and Associated Relief ("Petition") under Ind. Code §§ 8-1-2-61 and 8-1-2-42.7, Notice of Provision of Information in Accordance with the Commission's Minimum Standard Filing Requirements ("MSFRs"), and Request for Administrative Notice with the Indiana Utility Regulatory Commission ("Commission"). Petitioner also filed its case-in-chief, workpapers, administrative notice documents, and information required by the MSFRs set forth in 170 IAC 1-5-1.

NIPSCO provided testimony and exhibits from the following witnesses:[1]

- Violet Sistovaris, President with NIPSCO[2]
- Michael Hooper, Senior Vice President of Regulatory, Legislative Affairs, and Strategy with NIPSCO[3]
- Paul S. Kelly, Vice President of Major Accounts with NIPSCO

[1] NIPSCO also filed Petitioner's Confidential Exhibit No. 20-S1 and Confidential Exhibit No. 20-S2 providing support for its accounting adjustments.
[2] NIPSCO late-filed attachments to Ms. Sistovaris' testimony on February 5, 2019.
[3] NIPSCO originally filed the direct testimony of Benjamin Felton. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019. NIPSCO filed corrections to Mr. Felton's direct testimony on January 2, 2019. NIPSCO filed corrections to Mr. Hooper's testimony on January 2, 2019, and April 18, 2019.

- Jennifer L. Shikany, Director of Regulatory with NiSource Corporate Services Company ("NCSC")[4]
- Clifton Scott, State Finance Director with NIPSCO
- Patrick N. Augustine, Principal in Charles River Associates' Energy Practice
- Kelly R. Carmichael, Vice President of Environmental with NIPSCO
- Andrew S. Campbell, Director of Regulatory Support & Planning with NIPSCO
- Kimberly K. Cartella, Director of Compensation with NCSC[5]
- Victor F. Ranalletta, Associate Engineer and Project Manager of Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell")
- John J. Spanos, Senior Vice President with Gannett Fleming Valuation and Rates Consultants, LLC
- Michael D. McCuen, Director of Income Taxes with NCSC
- Vincent V. Rea, Director of Regulatory Finance and Economics with NCSC
- Paula A. Strauss, Director of Regulatory with NCSC[6]
- Bickey Rimal, Manager at Concentric Energy Advisors, Inc. ("Concentric")[7]
- J. Stephen Gaske, Senior Vice President of Concentric[8]
- Curt A. Westerhausen, Director of Regulatory with NCSC[9]

Petitions to intervene were granted to the following parties:

- Citizens Action Coalition of Indiana, Inc. ("CAC")
- Indiana Coal Council, Inc. ("ICC")
- Indiana Coalition for Affordable and Reliable Electricity ("ICARE")
- Indiana Municipal Utility Group ("IMUG")[10]
- Board of Commissioners of LaPorte County, Indiana ("LaPorte")
- Modern Forge Indiana, LLC
- NIPSCO Industrial Group ("Industrial Group")[11]
- NLMK Indiana ("NLMK")
- Northern Indiana Commuter Transportation District ("NICTD")
- Peabody COALSALES, LLC ("Peabody")
- Dennis Rackers ("Rackers")
- Sierra Club
- Walmart Inc. ("Walmart")

---

[4] NIPSCO filed corrections to Ms. Shikany's testimony on January 2, 2019.
[5] NIPSCO originally filed the direct testimony of Christopher D. Smith. NIPSCO filed corrections to Mr. Smith's testimony on April 18, 2019. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019.
[6] NIPSCO originally filed the direct testimony of Amy Efland. NIPSCO filed a Notice of Substitution of Witness on December 19, 2018.
[7] NIPSCO filed corrections to Mr. Rimal's testimony on January 22, 2019.
[8] NIPSCO filed corrections to Dr. Gaske's testimony on January 22, 2019.
[9] NIPSCO filed corrections to Mr. Westerhausen's testimony on January 2, 2019, January 22, 2019, June 7, 2019, and July 2, 2019.
[10] The companies that comprise IMUG are Town of Highland, Town of Schererville, Town of Munster, Town of Dyer, Town of Griffith, Town of Winfield, City of East Chicago, and City of Valparaiso.
[11] The companies that comprise the Industrial Group are Accurate Castings, Inc., Arcelor Mittal USA, BP Products North America, Inc., Cargill, Inc., Enbridge Energy, Praxair, Inc., and USG Corporation.

- United States Steel Corporation ("US Steel")
- United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial Service Workers International Union AFL-CIO/CLC, and its Locals 12775 and 13796

By docket entry dated November 21, 2018, the Commission established a procedural schedule in this matter.[12] On February 13, 2019, the Indiana Office of Utility Consumer Counselor ("OUCC") and Intervenors filed their respective cases-in-chief. The Commission conducted a Public Field Hearing on March 11, 2019, at Hammond High School Auditorium. At the Field Hearing, members of the public appeared and made statements to the Commission.

The OUCC provided testimony and exhibits from the following witnesses:[13]

- Michael D. Eckert, Assistant Director of Electric Division
- Neha Medhekar, Utility Analyst II
- Wes R. Blakley, Senior Utility Analyst[14]
- J. Randall Woolridge, Professor of Finance, Smeal College of Business Administration, the Pennsylvania State University
- William H. Novak, President, WHN Consulting
- Peter M. Boerger, Ph.D., Senior Utility Analyst
- Glenn A. Watkins, President and Senior Economist, Technical Associates, Inc.

CAC provided testimony and exhibits from the following witnesses:

- Jonathan Wallach, Vice President, Resource Insight, Inc.
- John Howat, Senior Policy Analyst, National Consumer Law Center

ICC provided testimony and exhibits from the following witnesses:[15]

- Emily S. Medine, Principal, Energy Ventures Analysis[16]

ICC / ICARE provided testimony and exhibits from the following witness:

- Charles S. Griffey, Energy Consultant

IMUG provided testimony and exhibits from the following witness:

- Theodore Sommer, Partner, London Witte Group, LLC

---

[12] The procedural schedule was modified by docket entries dated January 29, 2019, April 11, 2019, April 24, 2019, May 1, 2019, May 10, 2019, and May 31, 2019.
[13] The OUCC filed testimony and exhibits of David J. Garrett, Managing Member, Resolve Utility Consulting, PLLC and Lauren M. Aguilar, Utility Analyst with the OUCC that were not offered into evidence.
[14] The OUCC filed revisions to Mr. Blakley's testimony on April 10, 2019.
[15] ICC also filed testimony of Bradley D. Scott, Chief Operating Office, Jiangnan Environmental Technology, Inc. that was withdrawn on March 5, 2019.
[16] ICC filed revisions to Ms. Medine's testimony on March 19, 2019.

Industrial Group provided testimony and exhibits from the following witnesses:

- James R. Dauphinais, Managing Principal, Brubaker & Associates[17]
- Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates[18]
- Michael P. Gorman, Managing Principal, Brubaker & Associates[19]

NLMK provided testimony and exhibits from the following witness:

- James A. Lahtinen, Consultant[20]

Peabody provided testimony and exhibits from the following witness:

- Michael J. Nasi, Partner, Jackson Walker L.L.P.

Sierra Club provided testimony and exhibits from the following witness:

- Avi Allison, Senior Associate, Synapse Energy Economics, Inc.

Walmart provided testimony and exhibits from the following witness:

- Steve W. Chriss, Director, Energy Services[21]

US Steel provided testimony and exhibits from the following witnesses:[22]

- Brown D. Thornton, Director, NewGen Strategies and Solutions, LLC ("NewGen")
- Tony M. Georgis, Energy Practice President, NewGen[23]

On March 15, 2019, NIPSCO filed the rebuttal testimony of Violet Sistovaris, Michael Hooper, Paul S. Kelly, Jennifer L. Shikany, Clifton Scott, Patrick N. Augustine, Kelly R. Carmichael, Andrew S. Campbell, Victor F. Ranalletta, John J. Spanos, Michael D. McCuen, Vincent V. Rea, Paula A. Strauss, Bickey Rimal, J. Stephen Gaske, and Curt A. Westerhausen.[24][25][26]

[17] Industrial Group filed revisions to Mr. Dauphinais testimony on July 24, 2019.
[18] Industrial Group filed revisions to Mr. Phillips testimony on July 24, 2019.
[19] Industrial Group filed revisions to Mr. Gorman's testimony on May 17, 2019.
[20] NLMK filed revisions to Mr. Lahtinen's testimony on May 17, 2019.
[21] Walmart originally filed the testimony of Gregory W. Tillman and filed a Notice of Substitution of Witness on June 11, 2019.
[22] US Steel originally filed testimony of Constance T. Cannady, which was withdrawn on June 25, 2019.
[23] US Steel filed revisions to Mr. Georgis' testimony on March 7, 2019.
[24] NIPSCO filed corrections to Mr. Westerhausen's rebuttal testimony on June 7, 2019.
[25] NIPSCO originally filed the rebuttal testimony of Benjamin Felton. NIPSCO filed a Notice of Substitution of Witness on June 26, 2019. NIPSCO filed corrections to Mr. Felton's rebuttal testimony on January 2, 2019.
[26] NIPSCO originally filed the rebuttal testimony of Alan Felsenthal, Managing Director at PricewaterhouseCoopers LLP that was not offered into evidence.

Also on March 15, 2019, CAC filed cross-answering testimony of Elizabeth A. Stanton, Director and Senior Economist of the Applied Economics Clinic and a Senior Research Fellow at the Global Development and Environment Institute at Tufts University; ICC filed cross-answering testimony of Phillip Graeter, Manager at Energy Ventures Analysis; ICARE filed cross-answering testimony of Charles S. Griffey; US Steel filed cross-answering testimony of Tony M. Georgis; Sierra Club filed cross-answering testimony of Avi Allison; NLMK filed cross-answering testimony of James A. Lahtinen; and Industrial Group filed cross-answering testimony of James R. Dauphinais and Nicholas Phillips, Jr.[27]

On April 9, 2019, the Presiding Officers directed NIPSCO and the OUCC to respond to requests for information, to which NIPSCO and the OUCC responded on April 11, 2019, and April 10, 2019, respectively.

On April 26, 2019, NIPSCO, Industrial Group, NLMK, US Steel, CAC, Walmart, NICTD, Sierra Club, and the OUCC (the "Revenue Settling Parties") filed a Stipulation and Settlement Agreement on Less Than all the Issues resolving revenue requirement and other miscellaneous issues (the "Revenue Settlement"). On April 30, 2019, the Revenue Settling Parties filed a Status Update notifying the Commission that IMUG had joined the Revenue Settlement and provided an additional provision in the Revenue Settlement, specifically Paragraph 11.[28]

On May 17, 2019, in support of the Revenue Settlement, NIPSCO filed testimony of Violet Sistovaris, Jennifer L. Shikany, and Curt A. Westerhausen;[29] the OUCC filed testimony of Michael D. Eckert and Wes R. Blakley; and the Industrial Group filed testimony of Michael P. Gorman. Also on May 17, 2019, Sierra Club filed a Notice of Support for the Revenue Settlement.

On May 17, 2019, NIPSCO, Industrial Group, NLMK Indiana, and US Steel (the "Rate 831 Settling Parties") filed a Stipulation and Settlement Agreement on Rate 831 Implementation (the "Rate 831 Settlement").[30] Also on May 17, 2019, in support of the Rate 831 Settlement, NIPSCO filed testimony of Curt A. Westerhausen; Industrial Group filed testimony of Nicholas Phillips, Jr.; and US Steel filed testimony of Tony M. Georgis.

On June 7, 2019, in opposition to the Revenue Settlement, ICC filed responsive testimony of Emily S. Medine; ICC and ICARE filed responsive testimony of Charles S. Griffey; and LaPorte filed responsive testimony of Reed W. Cearley, a consultant.

On June 17, 2019, in opposition to the Rate 831 Settlement, OUCC filed responsive testimony of Peter M. Boerger; CAC filed responsive testimony of Kerwin L. Olson, Executive Director of CAC, and Jonathan Wallach; Walmart joined in the CAC's responsive testimony of Mr. Wallach; and Sierra Club joined in the OUCC's responsive testimony of Dr. Boerger and CAC's responsive testimony of Mr. Olson and Mr. Wallach.

---

[27] NICTD filed cross-answering testimony of Gerald R. Hanas, a consultant with GRH Commuter Rail Dynamics that was not offered into evidence.

[28] IMUG filed a Formal Notice of IMUG Joinder in Amended Partial Settlement Agreement on May 15, 2019.

[29] NIPSCO filed corrections to Mr. Westerhausen's Revenue Settlement testimony on June 7, 2019.

[30] The Rate 831 Settling Parties filed a revision to the Rate 831 Settlement on June 7, 2019.

On June 20, 2019, in reply to Revenue Settlement responsive testimony, NIPSCO filed reply testimony of Violet Sistovaris, Jennifer L. Shikany, Patrick N. Augustine, and Andrew S. Campbell.

On June 27, 2019, in reply to Rate 831 Settlement responsive testimony, NIPSCO filed reply testimony of Paul S. Kelly, the Industrial Group filed reply testimony of Nicholas Phillips, Jr., and US Steel filed reply testimony of Tony M. Georgis.

On July 16, 2019, the Presiding Officers directed Walmart and LaPorte to respond to requests for information, to which Walmart and LaPorte responded on July 17, 2019.

On July 16, 2019, Rackers filed a Motion for Administrative Notice. NIPSCO filed its objection to the Motion on July 17, 2019. Rackers filed his reply to NIPSCO's objection on July 22, 2019. The Commission denied the motion by docket entry dated August 1, 2019.

On July 24, 2019, Rackers filed a Second Motion for Administrative Notice. NIPSCO filed its objection to the Motion on July 24, 2019. The Commission denied the motion by docket entry dated August 1, 2019.

The Commission held an Evidentiary Hearing in this Cause beginning on July 25, 2019, at 9:30 a.m. and continuing through August 5, 2019, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. All participating parties appeared, presented their evidence, and offered their witnesses for cross-examination.

TABLE OF CONTENTS

TOPIC	PAGE
1. Notice and Jurisdiction	8
2. Petitioner's Characteristics	8
3. Existing Rates	8
4. Relief Requested	8
5. Test Year	10
6. NIPSCO's Case-in-Chief	10
7. OUCC's Case-in-Chief	65
8. CAC's Case-in-Chief	73
9. ICC's Case-in-Chief	75
10. ICC/ICARE's Case-in-Chief	76
11. IMUG's Case-in-Chief	76
12. Industrial Group's Case-in-Chief	77
13. NLMK's Case-in-Chief	79
14. Peabody's Case-in-Chief	80
15. Sierra Club's Case-in-Chief	81
16. Walmart's Case-in-Chief	82
17. US Steel's Case-in-Chief	83
18. Cross-Answering Testimony	84
19. NIPSCO's Rebuttal Testimony	90
20. Overview of the Revenue Settlement	119
21. Revenue Settlement Supporting Testimony	122
22. Revenue Settlement Opposing Testimony	130
23. Revenue Settlement Reply Testimony	132
24. Overview of the Rate 831 Settlement	137
25. Rate 831 Settlement Supporting Testimony	139
26. Rate 831 Settlement Opposing Testimony	142
27. Rate 831 Settlement Reply Testimony	143
28. Commission Discussion and Findings	151
29. Confidential Information	170
30. Ordering Paragraphs	170
Attachment of Stipulation and Settlement Agreement on Less Than all the Issues	
Attachment of Stipulation and Settlement Agreement on Rate 831 Implementation	

Based upon the applicable law and evidence presented, the Commission now finds:

1. **Notice and Jurisdiction.** Notice of the filing of the Petition in this Cause was given and published by NIPSCO as required by law. Notice was given by NIPSCO to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Notices of the public hearings in this Cause were given and published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1. NIPSCO is also an energy utility as defined in Ind. Code § 8-1-2.5-2 and provides "retail energy service" as that term is defined by Ind. Code § 8-1-2.5-3. NIPSCO is also a utility within the meaning of Ind. Code § 8-1-2-42.7(c). NIPSCO is also subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Pursuant to Ind. Code §§ 8-1-2-42 and 42.7, the Commission has jurisdiction over NIPSCO's rates and charges for utility service. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** NIPSCO is a public utility with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana and provides gas and electric service ("NIPSCO Electric") in Indiana. NIPSCO is authorized by the Commission to provide electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren, and White Counties in northern Indiana.

3. **Existing Rates.** NIPSCO's current electric basic rates and charges were approved in the Commission's July 18, 2016 Order in Cause No. 44688 (the "44688 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement between NIPSCO and the majority of the intervenors (the "44688 Rate Case").[31] Those new basic rates and charges went into effect on September 29, 2016. The 44688 Rate Case Order approved, among other items, an increase in NIPSCO's basic rates and charges. In addition, on May 1, 2018, NIPSCO's basic rates were modified to reflect the reduction in the federal income tax rate from 35% to 21% as approved in the Tax Cut and Jobs Act of 2017 ("TCJA") pursuant to the Commission's January 3, 2018 Order in Cause No. 45032.[32]

NIPSCO's petition in Cause No. 44688 was filed with the Commission on October 1, 2015. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than 15 months have passed since the filing date of NIPSCO's most recent request for a general increase in its basic rates and charges.

4. **Relief Requested.** NIPSCO's Petition requests approval of the following:

A. Electric Service Tariff and Standard Contract. NIPSCO seeks approval of changes to its basic rates and charges for electric utility service that will provide NIPSCO with the opportunity to earn a fair return on the fair value of its property. NIPSCO seeks approval of changes to its Electric Service Tariff, including the elimination of Riders 772 and 775, changing the series number of its rate schedules to Series 800, and miscellaneous changes to its General

[31] The Stipulation and Settlement Agreement was entered into as of the 19th day of February, 2016, by and between NIPSCO, the OUCC, IMUG, Industrial Group, NLMK, US Steel, and United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO/CLC.
[32] The Commission approved NIPSCO's 30-Day Filing No. 50167 on April 25, 2018.

Rules and Regulations and Standard Contract. The overall structure of NIPSCO's tariffs remains the same for residential and commercial customers (except for a proposed increase in fixed recovery by increasing customer charges), but NIPSCO is proposing a new service structure for its industrial customers currently taking service under Rates 732, 733, and 734.

B. New Industrial Service Structure. NIPSCO requests that the Commission approve NIPSCO's proposal for a new industrial service structure as an alternative regulatory plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6. To the extent any other proposals of NIPSCO herein may require alternative regulation, NIPSCO requests that they be approved as an ARP. NIPSCO elects to become subject to the provisions of Ind. Code § 8-1-2.5-6 for purposes of any such proposals. NIPSCO requests that its proposed industrial service structure be found to be in the public interest pursuant to Ind. Code § 8-1-2.5-6.

C. Depreciation Rates. NIPSCO seeks approval to revise its depreciation accrual rates.

D. Previously Approved Environmental Compliance Projects and Federally Mandated Compliance Projects Depreciation Rates. NIPSCO has been recognizing for ratemaking purposes the cost of previously approved qualified pollution control property, clean coal technology, and clean energy projects (collectively, "Environmental Compliance Projects") and Federally Mandated Compliance Projects and associated operating expense through its Environmental Cost Recovery Mechanism ("ECRM") and its Federally Mandated Cost Adjustment ("FMCA") Factor. NIPSCO proposes to reflect in its basic rates and charges the capital costs and operating expenses associated with Environmental Compliance Projects and Federally Mandated Compliance Projects previously approved by the Commission in Cause Nos. 42150, 44012, 44311, 44340, 44872, and 44889 that were or are projected to be completed and in service at the end of the forward test year (December 31, 2019) and that are currently being recovered through the ECRM and FMCA. Since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECRM. When new tariff sheets are filed based upon the final order in this proceeding, NIPSCO proposes to adjust, as applicable, its then current FMCA adjustment factors to reflect the removal of the in-service plant and related expenses as of the same effective date, and modify its allocation factors consistent with the Commission's final order, subject to any necessary variance reconciliations in the ongoing FMCA proceedings.

E. Accounting Relief. NIPSCO seeks accounting authority to defer, as a regulatory asset, discounts offered to certain customers under its Economic Development Rider ("EDR") for recovery in a future rate case; authority to defer, as a regulatory liability, an amount equal to 100% of: (1) annual off-system sales ("OSS") margins net of expenses; (2) back-up and maintenance demand margins, both for pass back through the Regional Transmission Organization ("RTO") Tracker; and (3) authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired.

F. Demand-Side Management. NIPSCO proposes to exclude from its basic rates and charges all costs associated with its demand-side management ("DSM") program. NIPSCO has also adjusted its usage determinants for energy efficiency ("EE") measures installed

through December 31, 2017, consistent with Evaluation, Measurement, and Verification. NIPSCO has also adjusted its usage upward for EE measures installed between January 1, 2018 and December 31, 2019. NIPSCO proposes to reset lost margins in its DSM tracker filing upon new, effective base rates in this proceeding to eliminate lost margins attributable to all EE measures installed prior to December 31, 2017. Ultimately, NIPSCO is seeking a neutral transition to lost margin recovery between the filing of this rate case and the operation of its DSM tracker filing.

G. RTO Tracker and OSS Margin Sharing. NIPSCO proposes to update Rider 771 – Adjustment of Charges for Regional Transmission Organization (the "RTO Tracker") to: (1) remove Midcontinent Independent System Operator, Inc. ("MISO") charges and credits and collect 100% of MISO charges that are not included in the Fuel Adjustment Clause ("FAC") through the RTO Tracker; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO Tracker; (3) remove all back-up and maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology.

H. Environmental Cost Recovery Mechanism. NIPSCO proposes to discontinue its Rider 772 – Adjustment of Charges for Environmental Cost Recovery Mechanism and Appendix D – Environmental Cost Recovery Mechanism Factor.

I. Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with the Commission's orders.

J. Prepaid Pension Asset. NIPSCO's pension plan is currently in a net prepaid pension asset position, which is the net of the related pension obligation and regulatory asset in accordance with governing accounting standards. This prepaid pension asset reduces the pension cost that would otherwise be reflected in the revenue requirement and preserves the integrity of the pension fund. NIPSCO proposes that its rates reflect this asset as part of its capital structure.

5. Test Year and Rate Base Cutoff. NIPSCO proposed a forward-looking test period using projected data as authorized by Ind. Code § 8-1-2-42.7(d)(1). In the docket entry setting the procedural schedule, we found that the test year for determining NIPSCO's projected operating revenues, expenses, and operating income shall be the 12-month period ending December 31, 2019 ("2019 Forward Test Year" or "Forward Test Year"). The historic base period shall be the 12-month period ending December 31, 2017 ("2017 Historic Base Period" or "Historic Base Period"). The rate base cutoff shall reflect used and useful property at the end of the Forward Test Year.

6. NIPSCO Case-in-Chief.

A. Violet Sistovaris. Ms. Sistovaris provided a brief overview of NIPSCO and its role in northern Indiana. She provided an overview of NIPSCO's electric operations and customer base, and explained some of the challenges faced by NIPSCO's electric operations, such as its large industrial customer base (less than 1% of customers but over 56% of system energy sales, with the five largest customers constituting about 40% of NIPSCO's load). According to Ms. Sistovaris, this reliance on industrial sales represents a unique risk profile and makes NIPSCO's sales more susceptible to changes resulting from the business cycle. Due to the fixed

nature of many costs of providing electric service, reductions in sales volumes can have a significant impact to revenues, earnings, and other customers' rates.

Ms. Sistovaris testified that much of the infrastructure operated by the NiSource operating companies has been in service for many decades, and significant ongoing investment is required to maintain the systems in order to reliably meet current and long-term customer needs. For NIPSCO's electric service, this includes ongoing investments in Environmental Compliance Projects and investments in transmission and distribution assets. Ongoing investments in NIPSCO's electric distribution system is required as a result of: (1) new delivery infrastructure to serve new customers; (2) public improvements; (3) capacity enhancements; and (4) infrastructure replacements. Targeted transmission investment by NIPSCO individually and through its participation in MISO will continue. NIPSCO continues to balance the need for new investments with the cost to its customers. She stated that NIPSCO invested approximately $360 million in jurisdictional electric infrastructure through the 2017 Historic Base Period, and projects an additional investment of $520 million by the close of the 2019 Forward Test Year.

Ms. Sistovaris discussed significant changes to NIPSCO's generation fleet expected as a result of its 2018 Integrated Resource Plan ("2018 IRP"). She stated that on September 19, 2018, in a public meeting with interested stakeholders, NIPSCO announced the preliminary results of its 2018 IRP. The retirement analysis under the IRP currently indicates that NIPSCO will retire Units 17 and 18 at R.M. Schahfer Generating Station ("Schahfer") in 2023, as was indicated in the 2016 IRP. However, this updated retirement analysis also indicates that Units 14 and 15 at Schahfer may retire as early as 2023 and that Unit 12 at Michigan City Generating Station ("Michigan City") may also retire as soon as 2028. The earlier retirement of Units 12, 14, and 15 were driven mainly by economics in the wholesale markets.

Ms. Sistovaris testified NIPSCO's goal is to be the premier utility in Indiana in every aspect of its performance, including interaction with its customers. NIPSCO collects direct input and feedback from its customers through a range of methods, which is broadly referred to internally as its "Voice of Customer" process. Those feedback mechanisms include the J.D. Power Customer Satisfaction Surveys, MSR Group Surveys, NIPSCO's Community Advisory Panels, NiSource's My Energy Insights On-line Customer Panels, comments and complaints that are emailed or called into NIPSCO's Call Center, as well as the Commission's Consumer Affairs Division. Ms. Sistovaris testified that NIPSCO's focus on its customers has resulted in the fewest customer complaints per 1,000 customers at the Commission. She stated that in 2017, NIPSCO's customer care representatives handled 1,376,378 calls. NIPSCO's Average Speed of Answer was 28 seconds and its Abandon Rate was only 2.3%. In 2017, NIPSCO's First Call Resolution rate was 87%. In 2017, the Customer Satisfaction with CSR rate was 88%. These metrics have improved significantly since NIPSCO's last rate case.

Ms. Sistovaris explained steps NIPSCO has taken to help customers save energy and reduce their monthly bills. NIPSCO has continued to elevate its internal emphasis on EE including enhanced communication with the stakeholders such as governmental agencies, other utilities, and consumer parties. NIPSCO has dedicated staff to EE measures and manages the development and implementation of such measures. NIPSCO's electric EE programs have helped customers save more than one million megawatt hours ("MWh") from 2010 through June 30, 2018. NIPSCO offers a variety of programs for all customer and helps customers manage current energy costs and

to assist NIPSCO in reducing or deferring future generation needs. NIPSCO's EE plan for 2019-2021 provide a robust portfolio of cost effective programs. In addition, NIPSCO has specifically tailored programs to assist low-income customers and smaller commercial entities.

Ms. Sistovaris testified NIPSCO offers a low-income EE weatherization program to both NIPSCO gas and electric customers and proposed a low-income appliance replacement program in its electric EE proceeding. NIPSCO also offers a deposit program that provides a reduction in the total deposit amount for qualified low-income customers. She stated that NIPSCO is committing to establish a low-income collaborative with interested stakeholders to advance low-income assistance and weatherization programs.

Ms. Sistovaris testified that NIPSCO is filing this case to: (1) reflect the evolution of the market for electricity for NIPSCO as well as for its largest customers in NIPSCO's service structure; (2) reflect in base rates the recent capital investments into NIPSCO's electric system, including infrastructure modernization and environmental controls; (3) revise its depreciation rates to reflect the most recent information regarding planned retirements of its generating units; and (4) align its rates and charges required to maintain safe and reliable service. NIPSCO's proposals in this proceeding were made after initial discussion with various stakeholder groups.

Ms. Sistovaris explained that NIPSCO is evolving from being highly reliant on coal-fired generation to facing the prospect of the retirement of those resources in the near term. Despite currently strong economic conditions, NIPSCO Electric operations continue to face declining industrial usage driven by the development of customer-owned generation and uncertainty in some industrial markets based on international trade conditions. In addition, the industry is transforming toward increased reliance on gas-fired and renewable generation as reflected in the MISO markets.

Ms. Sistovaris stated that regulatory restrictions and environmental costs will increase NIPSCO's cost of producing energy, which will impact generation mix, customer demand, NIPSCO's profitability, and NIPSCO's cash flow. NIPSCO is also addressing compliance with regulations that address the handling and disposal of coal combustion residuals ("CCRs") and may need to address more stringent effluent limitation guidelines ("ELG") in the foreseeable future.

Ms. Sistovaris testified that major environmental controls installed since NIPSCO's last rate case include but are not limited to: (1) installation of ground water monitoring facilities at Bailly Generating Station ("Bailly"), Michigan City, and Schahfer; (2) installation of remote ash conveying facilities and material management areas at Michigan City and Schahfer; (3) and closure of the landfill pond at Schahfer to address the disposal and handling of CCRs. NIPSCO is also engaged in the installation of selective catalytic reduction ("SCR") Catalyst Layers to comply with NIPSCO's NOx Compliance Plan at Units 7, 12, and 14. The ground water monitoring facilities were placed in service prior to the close of the 2017 Historic Base Period, and the remaining investments are expected to be in service prior to the close of the 2019 Forward Test Year.

Ms. Sistovaris sponsored: (1) Attachment 1-B, a copy of NIPSCO's notice of its intent to file an electric rate case in accordance with the Commission's General Administrative Order 2013-5; (2) Attachment 1-C, a copy of each of the Publishers' Affidavits associated with the notices published in accordance with law and Commission practice; and (3) Attachment 1-D, a copy of the notice provided to residential customers within 45 days of the filing of NIPSCO's Petition.

B. Michael Hooper. Mr. Hooper testified that by filing this case, NIPSCO satisfies the requirement in Ind. Code § 8-1-39-9(d) that NIPSCO file an electric rate case before the expiration of the public utility's approved seven-year plan.

He also explained why NIPSCO is requesting a change in rates at this time. First, NIPSCO seeks to align depreciation rates for its coal-fired generating assets more closely to the expected useful life of those assets as projected in NIPSCO's 2018 IRP. Second, NIPSCO needed to address the impact of the TCJA. Third, NIPSCO is proposing a change in its large industrial service structure to address the changing economic landscape. He noted that the changes in industrial service structure is a natural evolution from the interruptible service offering that was initiated in NIPSCO's 2010 electric rate case (Cause No. 43969) and expanded in its 2015 electric rate case (Cause No. 44688). The interruptible credits and attendant registration of approximately 530 megawatts ("MW") of Load Modifying Resources ("LMR") at MISO facilitated the retirement of Bailly Units 7 and 8, the cost savings from which are included in this filing.

Mr. Hooper testified NIPSCO's overall revenue increase requested in this proceeding is approximately $21.4 million, or 1.4% above the revenue requirement of NIPSCO's 2015 rate case plus the inclusion of trackers that NIPSCO customers will be paying by the time the Step 2 rates in this proceeding are implemented. Mr. Hooper explained that since 2010, NIPSCO has been allowing its industrial customers to assume more market risk in exchange for supporting less of NIPSCO's production costs. He stated the new industrial service structure proposed here is the next step in this evolutionary process. He explained that in exchange for taking a set amount of contract demand for a period of five years, NIPSCO's largest, most sophisticated customers will be allowed to make more decisions regarding their energy procurement. Transitioning much of NIPSCO's industrial load to the proposed market-sensitive rate structure requires better cost recovery alignment resulting in a near-term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward. Mr. Hooper stated that if the economics continue and NIPSCO does not respond, there is a high probability that more industrial load will leave the system and with a low likelihood that it would return, at least in the near term.

Mr. Hooper testified that NIPSCO's coal-fired generating units have seen decreased usage in the economically optimized MISO market. He stated that with current natural gas prices, NIPSCO's coal-fired generating units that have historically been used to serve baseload find themselves being the marginal units. He stated that ramping up and down aging coal units causes increased maintenance costs because the units were not designed to operate in that manner. In addition, the recent responses to NIPSCO's Request for Proposals ("RFP") for generation provided more cost effective resources available to serve NIPSCO's load.

Mr. Hooper testified that with the Preferred Plan in NIPSCO's 2018 IRP, NIPSCO is proposing to retire all Schahfer coal-fired generating units by December 31, 2023, and its Michigan City Unit 12 by December 31, 2028. He stated that while the alternative depreciation study conducted by Mr. Spanos also uses these retirement dates, for purposes of calculating the economic benefit of NIPSCO's alternative plans, NIPSCO used a 2030 retirement date for all coal-fired units and assumed recovery of and on those assets over that period. The depreciation rates, which NIPSCO proposes to implement in this proceeding are based upon a December 31, 2030 date.

Mr. Hooper testified that due to the magnitude of the effect of the change in retirement dates for NIPSCO's remaining coal-fired generating stations, NIPSCO is proposing to mitigate the effects of a significant rate increase by recovering all remaining future accruals by the end of 2030, as opposed to the physical retirement date of the units. He stated that because the recovery of depreciation expense extends beyond the anticipated physical retirement date of the asset, when NIPSCO retires the coal-fired generation units at Schahfer by 2023 there will be a significant amount of remaining net book value. Mr. Hooper stated NIPSCO proposes to treat these retirements as extraordinary retirements. At the retirement date, NIPSCO would create a regulatory asset equal to the remaining net book value of the Schahfer coal-fired generating units. He testified that NIPSCO proposes that this regulatory asset be included in rate base and be amortized through December 31, 2030, in an amount equal to the annualized monthly level of depreciation expense based on the month preceding the retirement. He noted that NIPSCO's 2018 IRP analysis included the recovery of and on these assets through 2030.

Mr. Hooper explained that this treatment is appropriate because it mitigates the amount of rate increase necessary in this case by delaying NIPSCO's recovery of its return of and on its investments in coal generation assets. Second, it assures NIPSCO will receive the return of and on its generating assets that have served its customers well over the last few decades. Finally, it fairly balances the interests of NIPSCO's stakeholders. He stated that while shifting recovery past the end of the useful life causes a mismatch between those customers receiving value versus those paying for assets, 2030 is not so far into the future that too large a distortion will take place.

Mr. Hooper testified NIPSCO did not include in the proposed depreciation accrual rates any of the costs related to certain Asset Retirement Obligations ("ARO") that must be performed in compliance with the U.S. Environmental Protection Agency's ("EPA") CCR Rule. He explained that the federal regulations underlying the AROs have recently been revised, and the full impact of the regulations is not yet certain. He testified that NIPSCO intends to seek recovery of these costs in a future base rate proceeding or through its FMCA mechanism when NIPSCO is more confident in the effects of the regulations and its costs become better estimated.

Mr. Hooper testified NIPSCO is proposing to return both protected and unprotected excess accumulated deferred income tax ("ADIT") over the remaining life of the assets. He stated the treatment of protected excess ADIT is required by the Internal Revenue Service ("IRS") and the proposed treatment of the unprotected excess ADIT makes sense from a policy perspective as those continuing to pay for the assets will receive the offsetting credit for the return of the excess ADIT. He noted that shortening of the depreciation lives of NIPSCO's coal generation assets increases the speed at which excess ADIT is returned to NIPSCO's customers.

Mr. Hooper described NIPSCO's derivation of its proposed revenue allocation. He stated that NIPSCO began with a fully allocated cost of service study ("ACOSS") and then developed rates for NIPSCO's Rate 831 customers at parity utilizing the proposed industrial service structure and allocating 184.556 MW of demand at the meter to the industrial class. NIPSCO then allocated the additional revenue requirement from this case over all customer classes equally, resulting in a rate increase for all other customer classes of 11.76%. He stated that this methodology was chosen to avoid rate shock to its Residential customers and that if not for the mitigation, the rate increase would be approximately 32.2% for Residential customers.

Mr. Hooper provided an overview of NIPSCO's proposed rate design. He stated that NIPSCO had three overall policy objectives in the development of its proposed rates: (1) restructure the industrial rate classes to accommodate the large industrial customers that want to reduce their dependence on NIPSCO generation; (2) moderate rate shock for the other rate classes; and (3) ensure rate design calculations are simple and transparent. With regard to its Residential customer charge, he testified NIPSCO proposes to take a relatively small step towards further fixed-variable alignment. Specifically, NIPSCO proposes to increase the customer charge that applies to residential and small commercial customers in a manner that simply improves recovery of the fixed costs to serve the customer and billing functions for customers. He testified the proposed residential customer charge of $17 per month would improve that alignment. He explained that based upon a full allocation of costs in the ACOSS, the customer costs alone support a charge of $21.47 and including the full fixed cost of the transmission and distribution system would support $49.76. He stated that those costs above $17 are still recovered through a variable charge. However, noting that the currently effective monthly customer charge is $14, in the spirit of gradualism, a $17 per customer per month charge is an appropriate step.

Mr. Hooper testified NIPSCO is proposing to increase its revenues by $21.4 million. He stated that a return equivalent to the weighted average cost of capital ("WACC") as applied to the net book value of NIPSCO Electric's assets reflects a fair return on the fair value of NIPSCO's used and useful property. This represents an overall increase of 1.4% to be allocated among NIPSCO's customers according to the rate design and COSS sponsored by Dr. Gaske and incorporated into the proposed tariffs sponsored by Mr. Westerhausen. He testified that NIPSCO collaborated with its stakeholders prior to making its filing including numerous meetings with the representatives of the settling parties to its last electric rate case to inform them about this filing and the issues driving it and to listen to any suggestions or concerns. Mr. Hooper testified NIPSCO seeks to promote simplicity, transparency, and collaboration with its stakeholders, respond to customers' needs, and reach a balanced set of proposals that is fair and reasonable.

C. Paul S. Kelly. Mr. Kelly testified the changing economic landscape includes the inefficiencies attributable to coal-fired generation and the availability of more economic alternatives within the MISO market. He stated that NIPSCO's large industrial customers utilize energy intensive processes, are sophisticated market participants, participate in energy markets globally, and compete on the basis of price globally. NIPSCO believes that now is the time to address the needs of its large industrial customers for a market-sensitive rate structure while it simultaneously addresses its on-going generation needs. He stated that in its 2018 IRP, NIPSCO performed analyses for each of its coal-fired units that evaluated the ongoing operations versus retirement and replacement under various potential future scenarios. NIPSCO used many factors in analyzing the retirement timing of the coal units including economics, cost risk, reliability risk, and impacts to NIPSCO's employees and the local economy. He testified that this filing requires its largest industrial customers to remain as NIPSCO's retail customers, while also providing more market choices and is synchronized with the preferred plan presented in NIPSCO's 2018 IRP. Mr. Kelly noted that an example of the changing landscape and resulting economics in the energy market is the March 29, 2018 Whiting Clean Energy, Inc. ("WCE") and BP Products North America ("BP") Joint Petition before the Commission (Cause No. 45071), which sought treatment of WCE as a Qualifying Facility ("QF") able to provide energy directly to BP.

Mr. Kelly provided the estimated annual margin losses for losses from aggregation of the WCE and BP Refinery based on the existing Rate 733 tariff and testified that it is both possible and probable for other industrial customers to reduce their firm loads. He stated that some large customers, like BP, may utilize new or existing cogeneration systems to reduce their firm requirements, and NIPSCO is already aware that other large industrial customers are considering expansion of their cogeneration facilities. Others may reduce those loads by shifting their industrial production to other, more economic locations outside Indiana. Mr. Kelly testified that because large industrial sales constitute such a significant portion of NIPSCO's retail electric sales, NIPSCO would experience decreased revenues and operating margins far faster than could be offset by growth in other sectors. He stated that in the long run, such load loss would subject remaining customers and customer classes to increased costs.

Mr. Kelly testified that after months of discussion with its largest industrial customers, NIPSCO is proposing a new Rate 831 market-sensitive industrial service structure. He stated that over the years, NIPSCO has allowed its largest customers to incur more market risk in exchange for supporting less of NIPSCO's production costs. In Cause No. 43969, NIPSCO expanded its long-standing use of interruptible service to be of use in the evolving MISO market. In Cause No. 43969, NIPSCO transitioned from special contract-based interruptible service offerings to tariff Rider 675. Seven customer historically interruptible premises took service subject to that new Rider, and NIPSCO's capacity requirements in the MISO market were reduced by approximately 377 MW. In Cause No. 44688, NIPSCO expanded the availability of the interruptible rate at the request of its industrial customers, and its interruptible customers allowed NIPSCO to reduce its capacity requirements by approximately 530 MW, which ultimately led to the earlier closure of Bailly Units 7 and 8. He stated that this interruptible/curtailable design, the reductions in NIPSCO's industrial load, and the current electric generation economic landscape lead NIPSCO and its industrial customers to believe that the time has come to allow further access into the energy marketplace while retaining NIPSCO's provision of retail service.

Mr. Kelly testified Rate 831 will replace Rates 732, 733, and 734 and Rider 775 for NIPSCO's largest industrial customers. He stated the availability requirements for Rate 831 are: (1) any transmission or sub-transmission voltage-connected customer with a load of at least ten MW; (2) interval data recorder ("IDR") metering; and (3) a five-year contract. He explained that three tiers of service are offered under the rate, and the customer will be given the opportunity to be served under Tier 1 with either, or both, of the other two, Tiers 2 and 3. Mr. Kelly described the three tiers as follows:

> **Tier 1:** Under Rate 831, a customer is required to take a minimum of ten MW of Tier 1 firm service. Tier 1 rates were designed based on approximately 184 MW (measured at the meter) being subscribed from NIPSCO's five largest industrial customers (approximately 190 MW measured at the generator bus bar). Tier 1 is billed as a fixed demand charge for production and customer-related charges and is considered first through the meter for purposes of energy except when the customer is taking back-up or maintenance services. Tier 1 is subject to all applicable Riders as listed on Appendix A of the tariff filed in this proceeding. Tier 1 will be billed as first through the meter up to the applicable amount of Tier 1 contract demand. A customer is required to provide five years of notice to increase Tier 1 contract demand and must execute a new five-year contract for the increased service.

Tier 2: Tier 2 is a non-firm curtailable service. NIPSCO will register as an LMR at MISO that portion of a customer's Tier 2 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party. Under Tier 2, the customer will take all Energy at the MISO Day-Ahead Locational Marginal Price ("LMP") at the applicable Company Load Zone. Tier 2 is subject only to the non-production Riders applicable to non-firm service (currently the energy portion of NIPSCO's RTO tracker, and any North American Electric Reliability Corporation ("NERC")/Critical Infrastructure Protection ("CIP") components of NIPSCO's FMCA tracker). Tier 2 will be billed as second through the meter up to the amount of Tier 2 contract demand after calculating the amount of Tier 1 energy.

Tier 3: Tier 3 is also a non-firm curtailable service. NIPSCO will register as a LMR at MISO that portion of a customer's Tier 3 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party, but NIPSCO will only register a single LMR for any non-firm load if a customer chooses to take both Tier 2 and 3 service. NIPSCO, as the MISO Market Participant, will register participating customers as an Asset Owner at MISO, which will allow the customer access to the MISO Market Portal to carry out MISO Asset Owner functions. Tier 3 is subject to any NERC/CIP components of NIPSCO's FMCA tracker but not the components of the RTO Tracker that Tier 2 will be responsible for given that Tier 3 customers will be invoiced for those charges directly from MISO as an Asset Owner. If, under the MISO Asset Owner framework, a customer has not arranged for any third-party energy with NIPSCO as the contracting Market Participant, the customer will take all energy under this Tier 3 service at the market price (LMP at the applicable Company Load Zone plus all applicable MISO charges / transmission charges). All settlements associated with the customer's Asset Owner energy offers and demand bids will be passed through to Tier 3 customer. All three tiers will pay volumetric transmission charges for all energy delivered to their premises with a discount available for adjacent customer-owned premises that contain cogeneration facilities capable of outputting energy to NIPSCO's system. Tier 3 will be billed as last through the meter.

Mr. Kelly testified that under the proposed rate, if multiple premises are held under common ownership and at the same qualifying service voltage, NIPSCO will allow customers to aggregate those loads with IDR metering as a single service. He stated that each IDR meter qualifying for aggregation under the rate will be included in the customer's contract to avoid confusion on which meters will or will not be included within the aggregation calculations. Mr. Kelly testified that NIPSCO is requiring a five-year contract to balance the needs of all stakeholders. He stated that NIPSCO and its other customers need these Rate 831 customers to continue to contribute to the fixed costs of production long enough to achieve an orderly transition to NIPSCO's preferred plan in the 2018 IRP. He stated that without a five-year contract, these customers could have an incentive to reduce their contract demands to a level that would immediately require NIPSCO to file another rate case to reallocate the under-collected revenue to remaining classes. Also, without the five-year notice provision to increase the firm Tier 1 contract demand, NIPSCO could be forced to procure uneconomic capacity to meet the increased need due to the inability to properly evaluate and potentially construct required capacity resources. He stated this is especially problematic given the lead times to navigate the MISO interconnection queue

and construct various generation technologies with long useful lives. Considering these issues, he stated the five-year contract period provides a reasonable level of certainty for NIPSCO and its customers in moving to a structure that provides more market choices for Rate 831 customers.

Mr. Kelly testified NIPSCO is offering an alternative transmission charge solely to customers that are held under common ownership or affiliates (as defined in Ind. Code § 23-1-43-1), which are located on adjacent premises and have cogeneration facilities that can produce power at one premise and transfer that power across NIPSCO's transmission system to an adjacent premise owned by the customer or its affiliate. He stated that because such customers will need to use only a small portion of the NIPSCO transmission system to transmit power from one of its premises to an adjacent industrial premise, NIPSCO is proposing to provide a 70% discount on the transmission charge for power that is transmitted between the two adjacent, affiliated premises. He stated that while discounted, the rate will result in some transmission revenue from these customers that would not occur if they built their own lines between their premises.

Mr. Kelly testified NIPSCO currently has 15 customers (23 premises) taking service under Rates 732, 733, and 734, and only five customers (nine premises) have also taken service under Rider 775. Of those 15 customers, four have less than ten MW of demand at a single premise. He stated that NIPSCO expects all five of its largest industrial customers (14 premises) to take service under Rate 831 with the remaining ten customers expected to take service under NIPSCO's new Rate 830 including the four below ten MW which will be grandfathered onto the rate.

Mr. Kelly testified that transitioning NIPSCO's industrial load to the proposed market-sensitive rate structure requires better cost recovery alignment. He stated it will result in a near-term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward.

Mr. Kelly described what happens if the five large industrial customers take more or less than the 184 MW used to allocate production costs. He stated that NIPSCO is proposing a two-phase rate design approach with the following characteristics to mitigate that risk if necessary:

> **Phase 1 Filed Rates:** The as-filed rates for Rate 831 were designed with the ACOSS allocating 184.556 MW (measured at the customer meter) of NIPSCO's fixed production cost to Rate 831's Tier 1 service for the five largest industrial customers (or 189.794 MW measured at the generator bus bar). This level of firm demand was based upon numerous conversations with NIPSCO's five largest customers. NIPSCO is proposing that customers will choose Tier 1, 2, and 3 contract levels within 30 days following the final order from the Commission in this rate proceeding. NIPSCO will also adjust the RTO Tracker allocations based upon the customer's choices regarding Tiers 1, 2, and 3. Any revenue shortfall resulting from an unsubscribed portion of the 184.556 MW will require a second phase true up.
>
> **Phase 2 Rates True-Up:** If, after the final order, the total amount of Tier 1 firm service chosen by the five largest industrial customers is different than 184.556 MW, final rates will be set in the Phase 2 rates to collect the appropriate revenue.

NIPSCO will also adjust the RTO Tracker allocations based upon the customer's choices regarding Tiers 1, 2, and 3.

Mr. Kelly briefly described NIPSCO's new Rate 830. He stated NIPSCO recognized not all of its largest industrial customers would be interested in the market-sensitive service under Rate 831. As such, NIPSCO designed Rate 830 to provide an industrial service that is similar to the current Rate 732, with a few exceptions. He explained that between Rate 830 and 831, NIPSCO's largest industrial service customers will be able to select a service option that meets their needs for firm service and their tolerance for different levels of market risk.

Mr. Kelly testified NIPSCO's proposed new industrial service structure is in the public interest as required by Ind. Code ch. 8-1-2.5 for approval of an ARP. He stated that Rate 831 will only be offered to energy intensive, highly sophisticated customers that compete directly or indirectly in a global market. He stated that traditional retail service at fixed rates as determined by the Commission is no longer necessary for the large industrials loads capable of being served through curtailable services with products from the FERC-regulated MISO capacity and energy markets. He stated that the Commission's approval of this innovative service structure is beneficial to NIPSCO's industrial customers, its remaining firm customers, and to NIPSCO. He explained that NIPSCO is currently implementing the preferred plan from its 2018 IRP for best serving its customers with generation capacity and that to the extent its future generating needs can be reduced, all customers will benefit. Mr. Kelly stated that approval of this new service structure will provide more accurate price signals, in that customers will be paying the market rate for energy and will be economically incented to adjust their consumption based on market price signals.

Mr. Kelly testified NIPSCO's proposed service structure is critical for retaining the level of industrial production from NIPSCO's largest customers. He stated it is crucial for NIPSCO's other 468,000+ customers that these Rate 831 customers continue to make a contribution to NIPSCO's fixed production costs through their retail electric utility service. He stated that NIPSCO has directly observed the loss of load when customers relocate production out of northern Indiana to other facilities that they own across the country and the world. NIPSCO has also experienced the near total loss of major industrial customers due to the inability of the customer to maintain economic viability. He stated that if a major employer closes its doors or even reduces the number of operating shifts in NIPSCO's service territory, it will negatively impact the broader economic stability of the region as well as hinder NIPSCO's ability to provide reasonably adequate service at just and reasonable rates. Mr. Kelly stated that those job losses can create a ripple effect that eventually impacts local governments and commercial businesses. In short, Mr. Kelly testified this proposed structure will best position these large industrial customers to remain cost competitive within their global markets while also contributing to NIPSCO's fixed production costs to serve. He stated that with those customers remaining and potentially expanding their industrial production in the region, this service structure could also mean the difference between a growing local economy in northern Indiana or one that is losing jobs and seeing reductions in its skilled labor force and property tax base.

Mr. Kelly testified that NIPSCO is unique in that its large industrial customers have historically accounted for more than 50% of its energy sales. As those customers compete globally, they are demanding electric rates that more accurately reflect the marginal cost of energy production. He testified that as NIPSCO considers retirement of its coal-fired generation and its

replacement alternatives, it presents a unique opportunity to address NIPSCO's industrial customers' needs, while offering protection to its remaining customers that they will not be responsible for replacement generation cost to serve industrial load that is more volatile and more able to leave the system with stranded cost. Mr. Kelly testified NIPSCO's proposed industrial service structure balances the interests of all stakeholders and positions NIPSCO to provide safe and reliable service at just and reasonable rates.

D. Jennifer L. Shikany. Ms. Shikany presented the results of NIPSCO's electric operations for the Historic Base Period and the projected results for the Forward Test Year adjusted on a pro forma basis for the normalization and annualization of certain amounts included in these periods. Ms. Shikany quantified the amount by which retail electric revenues should be increased so that NIPSCO may have the opportunity to earn a fair and reasonable return.

Ms. Shikany testified NIPSCO's proposed rates are based on a forward-looking test year beginning January 1, 2019 and ending December 31, 2019, consistent with Ind. Code § 8-1-2-42.7. She stated NIPSCO provided information for the Historic Base Period and the period beginning January 1, 2018 and ending December 31, 2018 (the "2018 Budget Period"), for comparison purposes. She stated NIPSCO proposed both ratemaking and forward-looking adjustments to the Historic Base Period and Forward Test Year to support the forecasted amounts for the Forward Test Year and the normalization and annualization of these test periods. NIPSCO elected to proceed under the Commission's rules on the MSFRs (170 IAC 1-5-1 through 16) and followed Appendix B to the Commission's Recommended Best Practices for Rate Cases Submitted under Ind. Code § 8-1-2-42.7 (GAO 2013-5) as it relates to the MSFRs and the supporting documentation for changes between the Historic Base Period and the Forward Test Year.

Ms. Shikany testified that NIPSCO proposes retail electric rates designed to recover through base rates the gross retail electric revenue in the amount of $1,545,815,189, an increase of $21,371,413 over the forecasted test year pro forma results based on current rates. She also noted that rates based upon this level of annual revenue requirements will provide NIPSCO with an opportunity to earn annual jurisdictional net operating income ("NOI") of $288,763,895. She stated NIPSCO's proposed rates were calculated using NIPSCO's requested return on the Forward Test Year original cost rate base and capital structure. She stated NIPSCO is proposing to implement the requested rate relief in this proceeding in a two-step process to reasonably reflect the utility property that is used and useful at the time rates are placed into effect.

Ms. Shikany sponsored Attachments 4-A-S1 through Attachment 4-C-S1, Attachments 4-A-S2 through Attachment 4-C-S2, Attachment 4-A-S2-A1, Attachment 4-A-S2-A2, and Attachment 4-D. The reference to "S1" represents the attachments for Step 1 rates (based on an actual rate base, and related depreciation and amortization expense, and capital structure as of the June 30, 2019 proposed cutoff date). The reference to "S2" represents the attachments for Step 2 rates (based on an actual rate base, and related depreciation and amortization expense, and the actual capital structure as of the December 31, 2019 Forward Test Year cutoff date). The reference to "A1" represents the attachments for an alternate revenue requirement if the Commission does not approve NIPSCO's proposed change in service structure. The reference to "A2" represents the attachments for a second alternate revenue requirement if the Commission does not approve NIPSCO's proposal to extend the collection of coal-fired generation depreciation expense until December 31, 2030, and the exclusion of costs to comply with the demolition study's AROs.

Ms. Shikany described the development of the revenue requirements for the Forward Test Year. She stated the proposed revenue requirement was based on NIPSCO's 2019 budget adjusted for ratemaking and service structure adjustments. She noted that for each revenue requirement component, NIPSCO provided support and models to describe the changes from the 2017 actual results to the 2019 forecasted amounts which are used for ratemaking purposes.

Ms. Shikany provided separate, detailed explanations for each of NIPSCO's proposed pro forma adjustments to revenue, fuel and purchased power costs, operations and maintenance expenses, depreciation and amortization expense, and tax expense as part of her direct testimony. She also sponsored Rate Base amounts quantifying NIPSCO's December 31, 2019 forecasted net original cost rate base.

Ms. Shikany testified that the Bailly retirement was accounted for as a normal retirement pursuant to the FERC Uniform System of Accounts. Upon retirement, depreciation reserve was debited and utility plant was credited for the original cost. Treating Bailly as a normal retirement had the effect of assigning sufficient depreciation reserve from other generating stations to Bailly for purposes of the depreciation rates herein proposed, as explained by NIPSCO witness Spanos. Certain Bailly assets that were classified as production plant prior to the retirement of the generation units are now being used as transmission assets. The original cost and accumulated depreciation related to the assets that now comprise the Bailly synchronous condenser were transferred from production plant to transmission plant. She stated that all remaining balances were retired – Bailly Unit 7 in May 2018 and Bailly Unit 8 in February 2018. She stated that NIPSCO removed the original cost of the assets from gross plant and accumulated depreciation at the respective retirement dates of the unit. She testified the remaining net book value of Unit 7 and Unit 8 was a debit balance in accumulated depreciation of $102,923,994 and $142,329,364, respectively. This debit represents unrecovered amounts at the date of the retirement. Until NIPSCO's rates are changed, they are calculated to collect depreciation expense associated with Bailly. Ms. Shikany testified the FERC Uniform System of Accounts prohibits the continued use of the Depreciation Expense and Accumulated Depreciation accounts once an asset is retired. She stated that by recognizing that NIPSCO has continued to collect the return of depreciation expense through base rates, a regulatory liability has been established to account for this amount. She stated the $28,675,931 regulatory liability reported in Adjustment RB 6-19R is equal to the total amount of depreciation expense that would have been recorded had NIPSCO not retired the assets. She testified NIPSCO is requesting authority to include the regulatory liability as a line item in Accumulated Depreciation, which lowers the net book value of NIPSCO's rate base. She noted that if this adjustment is not included, Forward Test Year Rate Base would be overstated.

Ms. Shikany testified that because the AROs are new, estimated costs to close the ash ponds have generally not previously been included in NIPSCO's demolition studies and therefore, have not been included in the calculation of prior depreciation accrual rates or recovery of depreciation expense. She stated that in the normal course of business, all of the anticipated demolition costs would be included in the demolition study, which is an input in the net salvage calculation in the depreciation study. She explained that depreciation accrual rates would be designed to collect the remaining future accruals, which are equal to the net book value of the asset plus any net salvage, over the remaining useful life of the asset. Ms. Shikany testified that the demolition study sponsored by Mr. Ranalletta (Petitioner's Exhibit No. 12, Attachments 12-A through 12-D) and resulting depreciation accrual rates sponsored by Mr. Spanos (Petitioner's Exhibit No. 13,

Attachments 13-B and 13-C) includes the recovery of anticipated demolition costs, with the exception of costs required to comply with the AROs. She stated that NIPSCO has excluded the costs to comply with the AROs from the demolition study as the full impact of the regulations is not yet certain and in an effort to reduce the overall base rate increase to customers. She stated that NIPSCO will thus not be recovering through depreciation accrual rates approved in this Cause the costs to comply with the AROs.

Ms. Shikany testified NIPSCO is filing an alternate demolition study to demonstrate how inclusion of the costs to comply with the AROs in the demolition studies would impact the study results. She stated that inclusion of the costs to comply with the AROs in the demolition studies would increase the total demolition costs for steam production assets by $141,519,000 from $167,232,000 to $308,751,000. She stated that inclusion of the costs to comply with the AROs in the demolition studies would increase the remaining future accruals calculated in the depreciation study, which is equal to the net book value of the asset plus any net salvage. She testified that if these additional $141,519,000 costs were collected in the proposed depreciation rates, the annual depreciation expense would increase.

With regard to NIPSCO's announced plan to retire all coal-fired generation at Schahfer by 2023 and Michigan City by 2028, Ms. Shikany stated that in the normal course of business, the depreciation study would utilize the physical retirement dates of each generating station unit to calculate the remaining useful life of the unit. The future accrual, which is equal to the net book value of the asset plus any net salvage, would then be divided by the remaining useful life of the asset in order to determine the annual depreciation accrual required to collect all remaining accruals by the physical retirement date. She stated that due to capital additions, the inclusion of costs to comply with the AROs in the demolition study, and the acceleration of retirement dates for the coal generation assets, the annual depreciation accrual for Total Steam Production Plant increased by $311,908,329 from $132,449,341 in Cause No. 44688 to $444,357,670 in the alternate depreciation study in Petitioner's Exhibit No. 13, Attachment 13-D. An increase in annual depreciation expense of this magnitude would result in a significant increase in customer rates.

Ms. Shikany explained that in order to mitigate the effects of such a significant rate increase, NIPSCO is proposing to recover all remaining future accruals by the end of 2030, as opposed to the physical retirement date of the units. She stated that under this scenario, the Total Steam Production Plant depreciation accrual decreased by $268,567,997 from $444,357,670 in the alternate depreciation study to $175,789,673 in the depreciation study proposed in this case (see Petitioner's Exhibit No. 13, Attachment 13-D). She testified that because the recovery of depreciation expense extends beyond the asset's anticipated physical retirement date, when NIPSCO retires the coal-fired generation units at Schahfer by 2023, there will be a significant amount of remaining net book value. She stated that NIPSCO proposes to treat these retirements as extraordinary retirements. She explained that at the retirement date, NIPSCO would create a regulatory asset equal to the remaining net book value of the Schahfer coal-fired generating units. NIPSCO proposes that this regulatory asset be included in rate base and be amortized through December 31, 2030, in an amount equal to the annualized monthly level of depreciation expense based on the month preceding the retirement. She stated that any final true-up between incurred costs and recoveries will be considered in a future base rate proceeding. Ms. Shikany testified that with the exception of the costs to comply with the AROs, demolition costs will continue to be recovered through rates as a component of depreciation rates. The costs to comply with the AROs,

however, will not be recovered through depreciation rates approved in this rate case under this proposal. The costs to comply with the AROs will instead be recovered in a future base rate proceeding or by seeking a Certificate of Public Convenience and Necessity ("CPCN") to approve the recovery of these costs through NIPSCO's FMCA.

Ms. Shikany testified that the retirement will be extraordinary for two reasons. First, the remaining net book value for the coal generation units at Schahfer will be significant. Second, after the retirement of Schahfer in 2023, the only coal-fired generation station that will remain is Michigan City Unit 12. She stated that once that unit is retired, there will be no other coal generation assets remaining from which depreciation reserve could be reassigned in order to treat the retirement as a normal retirement. Ms. Shikany testified that by extending the recovery of depreciation expense for the Schahfer coal generation units seven years beyond the anticipated physical retirement, NIPSCO will delay the recovery of these dollars to mitigate a significant increase in customer rates. She stated that in the normal course of business, all remaining future accruals would be recovered as depreciation expense through base rates over the remaining useful lives of the plants (anticipated physical retirement dates). If NIPSCO delays the cash recovery of these dollars for an additional seven years, NIPSCO should be compensated by earning a return on remaining net book value in a future rate case. She stated that in order to mitigate NIPSCO's financial risk, NIPSCO is seeking authority from the Commission to defer the remaining net book value of coal generation assets as a regulatory asset within rate base. This authority reduces the risk of a Generally Accepted Accounting Principles ("GAAP") write-off of the remaining net book value of coal generation assets, which would have a negative impact on the financial statements and the investor community. Furthermore, a delay in the cash recovery beyond the useful life of the related assets without assurance that the remaining net book value of the coal generation assets as a regulatory asset in rate base could result in a negative impact on NIPSCO's credit ratings resulting in an increase in its cost of capital. She stated that NIPSCO maintains that the inclusion of this regulatory asset in NIPSCO's next base rate proceeding will alleviate these financial pressures by providing NIPSCO a return on its prudently incurred investments along with predictable and stable levels of cash flow through 2030.

Ms. Shikany described the adjustment made to the Utility Plant In Service component of rate base. She testified one of those adjustments is for the prepayment for assets relating to NIPSCO's investment in a new cloud-based Procure-to-Pay ("P2P") system. She explained that the new system will allow for replacement of multiple fragmented and obsolete technology systems related to sourcing, procuring, and paying for goods and services and also allow NIPSCO to automate and standardize business processes, manage standard settlement terms with suppliers, take advantage of new methods of settling payments, leverage centralized purchasing data, and manage spend on goods and services. She stated that NIPSCO has identified cloud computing services as a means to enhance security and to increase reliability and flexibility. She stated that to realize these benefits, NIPSCO plans to utilize cloud-based technologies beyond the P2P system. Ms. Shikany testified NIPSCO is requesting authority to account for off premise cloud-based technology solutions in the same way that it accounts for on-premise technology solutions. She explained that this would mean that NIPSCO would capitalize implementation services, internal labor, and other fees (such as those for licenses, maintenance, and support) that were necessary to bring the asset into service in FERC Account 303 – Intangible Plant for ease of tracking and identification. She explained that under the current GAAP accounting guidelines, certain costs incurred for the development of on-premises software are required to be capitalized, while certain

implementation costs for cloud-based services are considered prepaid expenses. Many cloud-based services offer advantages to traditional on-premises software such as greater flexibility for the workforce, improved productivity, and higher efficiency at lower costs relative to certain on-premises solutions. Accordingly, since cloud-based prepaid expenses are expected to provide benefits over extended periods of time and not just in the period in which the costs are incurred, NIPSCO believes that the prepaid expenses should be included in rate base and receive the same regulatory treatment as an on-premises solution, which is capitalized in FERC Account 303 – Intangible Assets. Ms. Shikany testified that NIPSCO believes that investments in prepaid expenses related to cloud-based assets are part of the reasonable cost of bringing NIPSCO's property to its current state of efficiency. NIPSCO proposes to amortize off-premises assets over the period of time that NIPSCO will use the new solution. In this case, the contract period for the cloud-based solution is five years so a five-year period will be used to amortize the asset.

Ms. Shikany described NIPSCO's proposed changes to its currently approved Riders. NIPSCO is proposing all Utility Receipts Tax ("URT") will be removed from the Riders as NIPSCO is proposing that URT will be a separate line item on the customer bill. NIPSCO is proposing to update Rider 770 – Adjustment of Charges for Cost of Fuel Rider to update the cost of fuel included in base rates. NIPSCO also is proposing to update Rider 771 – Adjustment of Charges for Regional Transmission Organization to reflect updated base levels of MISO non-fuel costs and revenues and OSS margins and proposing the pass back of any back-up and maintenance demand revenue. Finally, NIPSCO is proposing to eliminate the ECR Mechanism.

Ms. Shikany testified NIPSCO is seeking accounting authority to: (1) defer, as a regulatory asset, discounts offered to certain customers under its EDR for recovery in a future rate case; (2) defer, as a regulatory liability, an amount equal to 100% of (a) annual OSS margins net of expenses and (b) back-up and maintenance demand margins, both for pass back through the RTO Tracker; and (3) defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. She testified such deferred accounting is consistent with GAAP and FERC Uniform System of Accounts.

Ms. Shikany testified that in March of 2017, the Financial Accounting Standards Board issued ASU 2017-07, a GAAP standard that changed the income statement presentation of Pension and Other Post-Employment Benefits ("OPEB") expense and limited the amount of expense eligible for capitalization. She stated the new GAAP standard requires disaggregation of the cost components of Pension and OPEB and only the service cost component will be eligible for capitalization to Property, Plant, and Equipment. NiSource adopted the standard January 1, 2018. She testified NIPSCO is accounting for the costs consistent with guidance from the FERC Docket No. AI18-1-000, which states "Jurisdictional public utilities and licensees, natural gas companies, and centralized service companies should record pension and post-retirement benefits other than pensions costs in their entirety in Account 926". She explained that based on this FERC Docket, the ASU 2017-07 GAAP changes need not apply to the FERC books and that all components of Pension and OPEB costs that have historically been reported in operating expenses will continue to be recorded in operating expenses.

Ms. Shikany supported NIPSCO's calculation of the 2018 and 2019 WACC shown on Attachment 4-B-S2, CS Module. She explained that the forecasted Prepaid Pension Asset represents the difference between the forecasted cumulative amount of cash contributions to

NIPSCO's pension trust fund and the forecasted cumulative amount of pension expense that will be recorded on NIPSCO's books and records in accordance with GAAP. She stated that NIPSCO included the balance of the Prepaid Pension Asset as a component of its overall WACC.

Ms. Shikany provided separate, detailed explanations for each of NIPSCO's proposed pro forma adjustments to its proposed capital structure, and she stated that NIPSCO's accounting and financial reporting policies and procedures conform to GAAP, rules of the Securities and Exchange Commission, and the FERC Uniform System of Accounts. In addition, she explained that NIPSCO's (and NiSource's) financial books and records are formally audited by its outside auditors, and these outside audits are supplemented by internal audits. She also discussed the various controls NIPSCO utilizes to ensure the accuracy of its accounting books and records and financial statements. She testified NIPSCO's books and records are also subject to audit by the OUCC, the Commission, and FERC.

E. Clifton Scott. Mr. Scott explained and supported: (1) the financial planning and budgeting processes used at NIPSCO; (2) NIPSCO's 2018 Annual Financial Plan (the "2018 AFP") for its electric utility covering the 2018 and 2019 plan years, which is the underlying basis for its rate request; and (3) the 2018 and 2019 budget adjustments not supported in other witnesses testimony. He summarized the processes used at NiSource and NIPSCO for development of capital and operation and maintenance ("O&M") budgets and longer-term financial plans. He explained the process that NiSource and NIPSCO use to develop robust and accurate budgets and financial plans, including engaging leadership and operations personnel and prioritizing safety, reliability, customer service, and compliance. He stated NIPSCO's budgeting process produces budgets that are reliable forecasts of future capital and O&M needs and expenditures.

Mr. Scott testified the revenue forecasting methodology results in an accurate estimate of revenues to be achieved during 2019, with the caveat that the revenue forecast presented in this case does not reflect proposed or anticipated revenues coming out of this proceeding. Mr. Scott testified that under current rates, NIPSCO Electric's revenues in 2019 are forecasted to be $1,776,342,377 based on the major assumptions used for customer usage volumes, cost of fuel and purchased power, and approved retail electric utility tariff rates.

Mr. Scott testified the O&M budgeting methodology results in an accurate estimate of expenses to be incurred during 2019. He stated NIPSCO Electric has experienced a variance of 0.2%, compared to its approved O&M budget over the last five years and demonstrates a high level of historical O&M budgeting accuracy by NIPSCO Electric. He concluded that these results should provide a high level of confidence and reliability as to the overall accuracy of the O&M expenses included in NIPSCO Electric's 2019 O&M budget.

Mr. Scott testified the capital budgeting methodology results in an accurate estimate of capital to be expended during 2019. He stated NIPSCO Electric has experienced a variance of 1.1%, compared to its approved capital budget over the last five years, which demonstrates a high level of historical capital budgeting accuracy. He concluded that these results should provide a high level of confidence and reliability as to the overall accuracy of the capital expenses included in NIPSCO Electric's 2019 capital budget.

Mr. Scott testified NIPSCO Electric's 2019 forecasted income statement and consolidated balance sheet were prepared in accordance with NIPSCO's normal forecasting processes and based on the consolidation of data provided by business units and various corporate departments. The forecast is fully integrated between the income statement, balance sheet, and statement of cash flows. He testified NIPSCO's forecasted consolidated 2019 statement of cash flows is a function of the items reflected in the forecasted balance sheet.

Mr. Scott described the major components of NIPSCO Electric's fuel and purchased power expense. He testified NIPSCO Electric's fuel and purchased power expense in 2019 is forecasted to be $486,393,871. Mr. Scott then described the major categories of NIPSCO Electric's O&M expenses as generation, transmission, distribution, operating and maintenance expenses, customer account expenses, and administrative and general expenses. Mr. Scott testified NIPSCO Electric's O&M expenses in 2019 are forecast to be $557,756,972. Mr. Scott also described the major components of NIPSCO Electric's tax expenses other than income taxes to be property taxes, payroll taxes, public utility fees, and URTs. He testified NIPSCO Electric's tax expenses, other than income taxes, in 2019 is forecast to be $66,011,931.

Mr. Scott stated the major components used in the development of the forecasted 2019 capital expenditures are Growth (also referred to as New Business), Tracker, Maintenance Betterment (capacity or compliance), Replacement (age and condition), Public Improvement (mandatory relocation), and Corporate (Shared Services). He testified NIPSCO Electric's capital expenditure in 2019 is forecast to be $417,526,573. He also testified NIPSCO Electric's Materials and Supplies and Production Fuel balances are $105,237,192 and $45,253,522, respectively.

Mr. Scott explained the major components of NIPSCO Electric's capital structure consist of Common Equity, Long-Term Debt, Customer Deposits, Deferred Income Taxes, Post Retirement Liability, Prepaid Pension Asset, and Post-1970 ITC. He testified NIPSCO's capital structure balances in 2019 are forecast to be $5,932,644,938.

F. Patrick N. Augustine. Mr. Augustine provided an extensive discussion of the analysis that was performed in NIPSCO's 2018 IRP and explained how that analysis was used in making the retirement decisions regarding NIPSCO's coal facilities. He stated that all five of NIPSCO's coal-fired units were evaluated for retirement, including Michigan City Unit 12 and Schahfer Units 14, 15, 17, and 18. He explained that the operational dependency as well as technology and vintage similarity of the units at Schahfer would make unit level retirement impractical at that plant and as a result, the analysis created two unit pairs that would be jointly considered for retention or retirement at Schahfer – Pair 1 matched Units 14 and 15, and Pair 2 matched Units 17 and 18. He stated that analyses were performed for NIPSCO's coal-fired units that evaluated the ongoing operations versus retirement and replacement of the units with an alternative under various potential future states of the world. He stated that NIPSCO used a number of factors in analyzing the retirement timing of the coal units including customer cost, cost risk, reliability risk, and impacts to NIPSCO's employees and the local economy.

Mr. Augustine described that customer cost and cost risk are measured by the overall Net Present Value of Revenue Requirements. He explained that the Cost to Customer metric is recorded under a Base Case set of market conditions. In addition, he noted that NIPSCO evaluated customer costs across three alternative market scenarios and at different points on a cost

distribution developed through a stochastic analysis. He explained that Reliability Risk assesses NIPSCO's ability to confidently transition the resources and maintain customer and system reliability and considers the activities required as part of the MISO retirement process, potential transmission system, and reliability upgrades that are required as a result of plant retirements, remaining unit dependencies, outstanding fuel and other contracts, future resource procurement, and the percent of NIPSCO's supply resources turning over at once. He noted other factors, such as the loss of work for employees and the reduction of property tax base for surrounding communities, also factored into the decision making process. He said that while these do not directly impact power supply costs to customers, NIPSCO believes they are factors that should be included in the analysis.

Mr. Augustine described that the retirement analysis evaluated eight retirement combinations and that the projected future capital and operating costs for the affected units were modeled by Charles River Associates ("CRA") in the Aurora production cost and utility portfolio model. He explained that the economic analyses ultimately compared the ongoing costs and benefits of operating the existing units to the costs and benefits of retiring and replacing the relevant unit or sets of units with alternatives. He stated the analyses were evaluated across all scenarios and stochastics developed in NIPSCO's IRP.

Mr. Augustine testified that capital cost estimates were developed by operational teams within NIPSCO for existing unit maintenance and environmental spend as well as for necessary transmission reliability upgrades in the instances where certain coal units retired. He stated that the existing rate base was depreciated at NIPSCO's latest estimate for the steam generation fleet average, which is 4.6%, across all retirement portfolios, which is consistent with the depreciation study presented in this Cause. He indicated that existing rate base is depreciated at the fleet average depreciation rate until the book value is equal to the total estimated "cost of removal," which is equal to $227 million for the entire fleet. He said that this depreciation schedule and cost of removal value were the same across all retirement cases, and thus, the analysis assumes that return of and on capital is recovered in all cases.

Mr. Augustine provided an extensive explanation of the resource alternatives used to evaluate the retirement options, the commodities price assumptions used in the analysis, and the process CRA used to complete the modeling analysis. He also addressed how risk and uncertainty were assessed in the analyses. Mr. Augustine sponsored the detailed modeling results in Attachment 6-A. He testified that in the Base Case, Retirement Combination 8 (where 100% of the coal portfolio is retired by 2023) is the lowest cost option, and Retirement Combination 1 (where all coal units run to 60 years of service) is the highest cost option. He testified that in the Base Case, Retirement Combination 6 (which retires Schahfer Units 14, 15, 17, and 18 in 2023, and Michigan City Unit 12 in 2028) is the third lowest cost option. He explained that the cost to customer ranking remains broadly consistent across the four scenarios analyzed. He explained that generally, portfolios that retain more coal perform relatively better in the scenario without a carbon price (Challenged Economy) and relatively worse when carbon prices are higher (Aggressive Environmental Regulation); however, in all four of the scenarios, retirement of all coal units (Retirement Combination 8) and replacement with a model-optimized selection of RFP alternatives is the least cost portfolio and that Retirement Combination 6, is the third-least expensive option. He testified that overall, the analysis concludes that the all-in costs of the replacements evaluated from the RFP are lower than the ongoing costs associated with maintaining

the existing coal fleet. Mr. Augustine also described the results of the IRP analyses with regard to the other, non-cost metrics.

Mr. Augustine testified how NIPSCO integrated the results of these analyses to arrive at a decision regarding coal retirements. He stated that NIPSCO created a scorecard to explore relative differences between the portfolios using a number of quantitative and qualitative measures. He stated that ultimately, NIPSCSO selected Retirement Combination 6 as the preferred retirement path, which would retire all of the Schahfer units by the end of 2023 and Michigan City by the end of 2028. He explained that Retirement Combination 6 was selected because it was the lowest cost and lowest cost risk option that held acceptable reliability risk for customers and the system. He said the analysis shows that Retirement Combination 6 saves customers $1.5 billion relative to NIPSCO's 2016 IRP preferred plan and that from a reliability risk standpoint it provides enough time to reasonably erect the necessary transmission upgrades that are critical for system and customer reliability. Additionally, the replacement resources can be reasonably secured and constructed by 2023. He stated that while the near-term transition still encompasses roughly 60% of NIPSCO's physical generation, it maintains Michigan City through 2028 and Sugar Creek Generating Station ("Sugar Creek") even longer. He noted that both are dispatchable units that can be used to support the transition while NIPSCO implements the replacement path. He also indicated that another benefit of staggering the retirements is that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade and adjust as appropriate rather than locking the entire transition in at once.

Mr. Augustine concluded that NIPSCO evaluated its generation portfolio under four fundamental market scenarios as well as with advanced risk treatment using stochastics. He stated that Retirement Combination 6 was selected as the preferred retirement portfolio combination. He testified that in this option, NIPSCO has balanced customer cost and cost risk with portfolio flexibility and the ability to successfully and reliably transform its supply resources to meet its customers needs. He noted that although not the least expensive solution, in all modeling analyses, the preferred portfolio results in savings to customers, greater cost certainty, and lower cost risk over alternatives that preserve more coal capacity for longer, as well as balancing other non-economic considerations such as portfolio flexibility, employees, and local property tax impacts.

G. Michael Hooper. Mr. Hooper adopted the testimony of Benjamin Felton, formerly NIPSCO's Senior Vice President, NIPSCO Electric, and that testimony was offered separately. In that testimony, Mr. Hooper described steps taken by NIPSCO to control costs, described NIPSCO's generation fleet, described NIPSCO's electric transmission and distribution systems, discussed NIPSCO's customer service and electric reliability programs, described the investments NIPSCO has made to its generation, transmission, and distribution systems in recent years, and explained and supported several various pro forma expense adjustments.

Mr. Hooper testified that NIPSCO's Net Utility Plant has grown by approximately $360 million or 12% over the last three years and is projected to grow by another $520 million by the end of the 2019 future test year. He noted that NIPSCO has taken steps to control costs resulting in decreases to O&M expenses, but explained that in spite of these efforts, increases in depreciation and amortization expense associated with the investment in new plant are projected to counter those savings. Mr. Hooper testified that department or cost center managers must prepare and submit proposed operating budgets to include proposed levels of capital and operating

expenditures. He explained that each operating budget is reviewed by management and that once approved, each manager is responsible for monitoring their budget to ensure the costs are spent within approved limits. Budgets and actual expenditure variances are reviewed throughout the year to ensure that funds are being spent appropriately and in accordance with approved levels to ensure that controls are in place to identify, monitor, and control costs.

Mr. Hooper described NIPSCO's six electric generation sites totaling 2,825 MW, including the Schahfer, Michigan City, Bailly, Sugar Creek stations, and two hydroelectric dams. He testified that NIPSCO's historic test period generating mix produced 73.3% of its output from coal-fired units, 26.3% from natural gas-fired units, and 0.4% from hydroelectric units. He noted that the Bailly Units 7 and 8 were retired on May 31, 2018, consistent with NIPSCO's expectations expressed in Cause No. 44688.

Mr. Hooper discussed NIPSCO's investments in environmental and emissions control projects and provided tables identifying the associated capital costs. He testified that NIPSCO obtained approval of its Environmental Compliance Plan consisting of several capital projects being tracked through NIPSCO's FMCA Tracker, noting that with one exception all projects incorporated in that Plan would be in service prior to the close of the Forward Test Year. He also detailed the components of the Utility Mercury and Air Toxics Standards ("MATS"), nitrogen dioxide ("NOx"), and MPCP Compliance Plans that had previously been the subject of approved CPCNs with costs for those projects recovered through NIPSCO's ECR tracking mechanism. Mr. Hooper testified that each of the components of the three Environmental Compliance Plans was in service and used and useful in the provision of electric service because they assist NIPSCO in meeting increasingly stringent air emissions requirements. Mr. Hooper also identified other capital improvements to NIPSCO's generation fleet since its last base rate case not already included in either the FMCA or ECR tracking mechanisms, and explained that those improvements are expected to be in service by the close of 2019.

Mr. Hooper summarized that the reliability of NIPSCO's generating units (exclusive of Units 7 and 8) as measured by the Equivalent Forced Outage Rate ("EFOR") has increased relative to the 44688 Rate Case, with NIPSCO's average EFOR for the three-year period ending December 31, 2017, increasing to 10.6% with the limited run time for the coal units during this period due to economic dispatch into MISO as a contributing factor. He explained that EFOR expresses unit reliability as a percentage of available run time for unplanned outage hours and equivalent unplanned de-rated hours. In contrast to NIPSCO's coal units, NIPSCO's Sugar Creek combined cycle gas turbine has been below 2.5% EFOR for each of the preceding three years, and under 1% in 2016, with a net capacity factor consistently above 65% and as high as 84% as of June 2018. He testified that the EFOR of NIPSCO's coal units was 9.79% in 2017, below the 2017 U.S. average of 10.92% for similarly sized units of between 300 – 599 MW.

Mr. Hooper explained that during the three-year period 2015 – 2017, NIPSCO's average EFOR was 10.63%. He noted that with recently announced coal plant retirements, there is the potential for EFOR to move upward over the near to medium term. Mr. Hooper explained that NIPSCO will continue to operate its facilities in a safe, environmentally compliant manner and with a reasonable level of reliability, while making sound decisions with regard to significant capital investments into facilities with limited operating lives. He testified that because NIPSCO's coal units were engineered to be used as baseload units that run consistently over long periods of

time, as those units become less economical, the cost to operate them increases because in addition to the increased maintenance required of older units, the added expenses to ramp the units up and down are incurred more frequently.

Mr. Hooper addressed NIPSCO's base cost of fuel and coal inventory levels. He testified that the adjusted retail jurisdictional cost of fuel in the Historic Base Period reported in Attachment 4-B-S2, FP Module was $494,884,095. He opined that this value was reasonable as discussed in NIPSCO's quarterly FAC proceedings. He added that both NIPSCO's long-term coal contracts and shorter-term gas supply contracts were the result of competitive bidding, and that NIPSCO considers a number of factors in making fuel procurement decisions, including price, quality, suitability, environmental attributes, supplier availability, reliability, and diversity in addition to market prices. Mr. Hooper testified that NIPSCO's retail jurisdictional coal inventory level reported in Attachment 4-B-S2, RB Module for the Historic Base Period was $80,046,953, and that it was reasonable and consistent with NIPSCO's desire to have adequate fuel supplies on hand while balancing the costs associated with maintaining coal inventory.

Mr. Hooper discussed NIPSCO's safety culture and described how NIPSCO and its consultant derived a plan to deliver human performance based error reduction through the use of improved safety metrics and a focus on an improved safety culture. He explained that in the past year, NIPSCO has engaged other consultants with expertise in safety regulations to work with internal teams to review and refine internal work practices, safety manuals, and safety policies/procedures while ensuring alignment with industry standards and best practices. He also explained that NIPSCO continues to collaboratively work with its front line employees to develop rules and policies for stronger work practices, and has developed a number of in-house safety training programs to improve driving performance and regulatory changes and requirements are continually monitored to manage safety training on a continual improvement basis.

Mr. Hooper testified that NIPSCO's contractors and construction execution teams have been engaged in its efforts to strengthen the safety culture, and NIPSCO has supported such measures by forming cooperative contractor safety committees for both its generation and field operations teams. He added that NIPSCO's focus on cooperation and safety has resulted in strong safety performance from its contracted teams. He testified that NIPSCO Electric has made an 80% improvement in recordable injury rate, an 83% improvement in DART (days away, restriction, or transfer) injury rate, and a 71% improvement in vehicle crash rate from year end 2008 to year end 2017, including a 66% improvement in recordable injury rate, a 72% improvement in DART injury rate, and a 71% improvement in vehicle crashes during that period.

Mr. Hooper described NIPSCO's transmission and distribution systems. He explained that NIPSCO's transmission system consists of approximately 353 circuit miles of 345 kilovolt ("kV"), 756 circuit miles of 138 kV, and 1,693 circuit miles of 69 kV transmission lines in addition to 63 transmission substations. He testified that NIPSCO is interconnected with six neighboring utilities, with transmission interconnects with American Electric Power or its affiliates (at 345 kV, 138 kV, and 69 kV), interconnects with Commonwealth Edison (at 345 kV and 138 kV), and with Duke Energy Indiana (at 345 kV, 138 kV, and 69 kV), in addition to 138 kV interconnections with Ameren and International Transmission Company and a single 765kV interconnection with Pioneer Transmission. He stated NIPSCO's distribution system serves more than 468,000 customers in northern Indiana, primarily through more than 900 distribution circuits operated at

nominal voltages of 34.5 kV, 12.5 kV, and four kV radiating from approximately 240 distribution substations, and encompassing about 8,209 miles of overhead line and about 2,532 miles of underground cable.

Mr. Hooper described the transmission and distribution investments made by NIPSCO since its 44688 Rate Case. These included investments in an Enhanced Outage Management System to provide faster restoration and more accurate communication scheduled to be in service in early 2019, more than $283 million in transmission, distribution, and storage system improvement charge ("TDSIC") direct cost investments through May 31, 2018, and other maintenance capital investments to expand and enhance capacity and reduce risk. Mr. Hooper explained that while significant investment had also been made in multi-value projects ("MVP") through MISO, those investments were not being included in jurisdictional rate base. He testified that all of NIPSCO's other transmission and distribution assets inclusive of the non-MVP additions are essential to the reliable transport and delivery of electricity from NIPSCO's generation fleet or from other generators to its retail customers in order to meet customers' needs for electric power and are used and useful in the provision of electric service.

Mr. Hooper explained that NIPSCO monitors three main metrics to evaluate the reliability of the transmission and distribution system: SAIFI, SAIDI, and CAIDI. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year. CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. Mr. Hooper testified that all three reliability indices have improved since the 44688 Rate Case and from 2014 to 2017. He explained that reliability indices are reported by industry standard without including Major Event Days, which primarily include storms or severe weather events. He noted that the decrease in Major Event Days in recent years is likely due in part to NIPSCO's aggressive vegetation management program and implementation of a comprehensive emergency restoration plan in 2017. He concluded that NIPSCO's transmission and reliability metric performance has been at or above industry standard performance for medium-sized electric utilities for the past five years.

Mr. Hooper testified about the programs NIPSCO uses to support transmission, distribution, and substation reliability and ensure compliance with NERC standards. These programs include wooden pole inspection, vegetation management programs, and periodic inspections and maintenance of transmission lines and structures, substation equipment, protective relay systems, distribution pad-mount transformers, pole-mounted re-closers, voltage regulators, switched capacitors, and other underground equipment that include remedial work necessary to repair or replace minor plant items found to be deficient. In 2017, NIPSCO developed and implemented a robust emergency response plan, and NIPSCO has also developed a formal Outage Investigation Program that reviews any outages that impact more than 1,000 customers, result in a pole fire or similar safety-related event, or have an "unknown" outage cause. Linemen, Substation Electricians, Supervisors, Dispatchers, and Engineers all benefit from these report findings by applying these lessons learned to their designs, materials, and construction methods to improve reliability, more accurately perform analytics on outage causes, and make improved decisions on materials, designs, construction methods, and maintenance techniques.

He also described NIPSCO's Line & Sub voltage regulator maintenance replacement program to reduce in-service failures. He testified that the program is intended to enhance customer reliability by incorporating newer regulators and enhanced tap changers that reduce contact wear and premature failure. He added that microprocessor-based controls have proven to be more reliable than analog controls, with the added benefit of enhanced customer voltage profile. He explained that NIPSCO continues its "Worst Circuits" and "Worst Taps" Programs whereby circuits and taps with the worst performance values and outages are assessed and recommendations for improvement are developed. Mr. Hooper noted that recommendations flowing from those programs have included targeted tree trimming, replacement of equipment prone to failure, replacement of equipment that is in poor condition, an analysis of fuse coordination and loading, and installing additional sectionalizing devices (cut-outs, triple-shots, re-closers, switches, etc.) where appropriate to minimize the impacts of outages and the number of customers affected per outage. Mr. Hooper explained that investment in an Enhanced Outage Management System expected to be in service in early 2019 to improve customer experience by providing faster restoration and more accurate communication of estimated time of restoration during outages.

Mr. Hooper supported a number of proposed adjustments found in Petitioner's Confidential Exhibit No. 20-S2. He testified that Adjustment OM 2A-17 increases non-labor Storm expense for the Historic Base Period by $1,336,602 to approximate a five-year average of storm expense, adding that both five- and seven-year analyses produced similar results. He explained that the Historic Base Period was a mild storm year, so Adjustment OM 2A-18 increases the 2017 normalized expense by $74,979 to reach the five-year average of $3,056,037 included in the 2018 Budget Period. Mr. Hooper also addressed the elimination of the Pure Air expenses in the amount of $10,702,282 and $8,568,689 for 2018 and 2019, respectively, because with the retirement of Bailly Units 7 and 8, the Pure Air flue gas desulfurization ("FGD") facility will no longer be required to operate and the associated expenses will no longer be incurred.

Mr. Hooper testified that Adjustment OM 2C-18 reduces forecasted Generation Base Maintenance expense by $6,785,009 as a reflection of: (1) a $1.9 million budget reprioritization decision; (2) a $2.4 million pull forward of 2018 budgeted dollars for the pre-purchase of materials, and; (3) a $1.1 million reduction in planned outages. He explained that while operationally advantageous, they were isolated opportunities and should not be reflected in the ongoing level of operating expenses. He added that Adjustment OM 2C-19 reflects an increase of $1,590,485 to reflect 2019 increases in cooling water chemical expenses anticipated for 2019. Mr. Hooper also discussed adjustments OM 2D-18 and OM 2D-19 to reduce Bailly non-labor Base Maintenance Expense by $3,600,000 and $3,800,000 in 2018 and 2019, respectively, due to the retirement of Bailly Units 7 and 8. He explained that the $3,600,000 reduction to the 2017 represents seven months of savings based on the retirement of the units in May, and that an additional $3,800,000 of savings in 2019 will bring the total Bailly Base Maintenance Expense savings to $7,400,000. He noted that the remaining Bailly base maintenance budget of $848,092 will be used to maintain the synchronous condenser unit and the Unit 10 combustion turbine still in service.

Mr. Hooper addressed adjustments to NIPSCO's Planned Outages normalization presented in Adjustment OM 2E-17 and its ongoing level of Planned Outages expenses in Adjustments OM 2E-18, 2E-19, and 2E-19R. He explained that Adjustment OM 2E-17 reduced the normalized level of Planned Outages for the base period by $25,455 based on the retirement of Units 7 and 8. He testified that Adjustments OM 2E-18 and OM 2E-19 reflect changes in amounts budgeted for 2018

and 2019 because the planned outage schedule varies from year to year by station, unit, and major component, and that Adjustment OM 2E-19R normalized non-Bailly planned outage expenses going forward to a three-year average of $30,437,740. For Forced Outages expenses, Mr. Hooper explained that Adjustment OM 2F18 reflects an increase of $119,959 to reflect 2018 budget expenditures, and Adjustment OM 2F-19R increases the ongoing level of Forced Outages expense to the average value of $5,261,129 actually experienced from 2015 through 2017.

Mr. Hooper described Adjustments OM 2G18, OM 2G-19, and OM 2G-19R regarding proposed adjustments to NIPSCO's Vegetation Management expenses. Mr. Hooper explained that since its last electric rate case, NIPSCO has increased the budget portion of its 69 kV, 34 kV, and 12 kV vegetation management programs to include more circuit-line miles and has begun analyzing circuits on a yearly basis to determine which circuits have had a higher experience of interruptions regardless of when the circuit was last trimmed. He explained that those circuits are surveyed, sources of tree interruptions are identified, and remedial work is performed. When compared to the same time frame (January through June) as last year, NIPSCO has experienced an overall reduction in tree related outages and customers impacted. He testified that in 2017 NIPSCO began to experience higher external labor and equipment costs to perform clearance work due to market conditions, and those changes were reflected in Adjustments OM 2G-18 and OM 2G-19 that increase Historic Base Period non-labor vegetation management expenses for 2018 and 2019. He noted that while NIPSCO has been prudent in managing vegetation costs, the overall impact of market constraints would lead NIPSCO to fall approximately 500 miles short of its 2019 circuit-mileage goal at current funding levels. As such, Adjustment OM 2G-19R was made to increase vegetation management expense by $5,720,500 to retain the 1,500 mile goal for 2019 allowing NIPSCO to continue to reduce vegetation-related outages.

Mr. Hooper also supported Adjustments OM 2H-17, OM 2H-18, and OM 2H-19R for Line Locate expenses. He testified that Adjustment OM 2H-17 decreases the Historic Base Period operating expense by $128,042 to reflect a full year of pricing and efficiencies gained under the terms of two locate contracts that became effective on March 8, 2017. He explained that the average ticket cost under NIPSCO's new locate contracts is $29.38 per ticket for combination gas and electric locates and $12.93 per ticket for electric only locates compared to the previous contract cost of $19.90 per ticket. He stated the incremental cost per ticket was then multiplied by the number of locates in the 12-month period between May of 2017 and April of 2018 to capture a full 12-month period of actual data to develop the normalized value. Mr. Hooper explained that Adjustment OM 2H-18 decreases the normalized Historic Base Period line locate expense by $522,189 to reflect the amount budgeted for line locating in 2018, and that Adjustment OM 2H-19R increases future test year locate expenses by $1,489,294 to reflect an increase in the projected number of 811 tickets in 2019 based on a projected increase in volume of 10.3% per year over the Historic Base Period volumes. These incremental 811 volumes were multiplied by 95¢ per ticket, and the incremental line locates volumes were multiplied by 2019 average screened prices to calculate the adjustments.

Mr. Hooper testified that Adjustment OM 2I-18 was made to reflect a decrease in Variable Chemical expense in the Historic Base Period by $1,164,262 driven by a change in the mix and quantity of chemicals required upon the retirement of Bailly Units 7 and 8. He explained that Adjustment OM 2I-19R reflects a reduction Variable Chemical expense of $551,509 to levelize it for reduced generation of 6.1 million MWh in 2019 based on updated PROMOD inputs and to

reflect the redistribution of the megawatt hours produced across NIPSCO's remaining units. Mr. Hooper stated Adjustment OM 2I-19SS was made to reflect the decrease in Variable Chemical expense for the Forward Test Year based on the proposed change in NIPSCO's service structure and the attendant loss of industrial load. Mr. Hooper also supported Adjustments OM 2J-18, OM 2J-19, and OM 2J-19SS that addressed Activated Carbon Injection ("ACI") expenses. He testified that Adjustment OM 2J-18 adjusted Historic Base Period ACI expenses to reflect reduction in ACI expenses as a result of the closure of Units 7 and 8 and an increase in ACI expenses at other units including increases associated with the increased output at Unit 15 during the Historic Base Period. The overall adjustment was an increase of $568,111. Mr. Hooper explained that Adjustments OM 2J-19R and OM 2J-10SS reflect a decrease in projected ACI expense for 2019 of $193,163 reflecting a projected decrease in Unit 15 output, and Adjustment OM 2J-19SS reflects a slight increase in projected ACI expense of $48,158 as a result of the implementation of NIPSCO's proposed service structure.

Mr. Hooper explained that the Long Term Service Agreement ("LTSA") expenses for Sugar Creek were incurred based on the unit's Run Time. He stated that Adjustment OM 2K-18 reflects an increase to the Historic Base Period of $115,416 in LTSA expenses for the 2018 budget based upon the increased Run Time of the Sugar Creek units, and that Adjustment OM 2K-19R was a ratemaking adjustment made to reflect changes in the LTSA contract executed after the preparation of the 2019 budget that decreases annual LTSA expenses by $3,774,547. He also sponsored Adjustment OM 2L-17 to decrease Historic Base Year Miscellaneous Expenses by $1,379,154 to remove expenses not budgeted as ongoing expenses.

Mr. Hooper explained that NIPSCO adjusted its projected 2019 O&M expenses downward by $3,890,900 to annualize the impact of a variety of cost savings initiatives including the use of a number of contracting options with vendors as well as in-sourcing some activities to increase efficiency. He also sponsored Adjustment OM 4B-19R to increase Forward Test Year operating expenses by $8,228,823 to reflect the ongoing level of O&M expenses associated with NIPSCO's MATS Compliance Project and MPCP Project currently being recovered through NIPSCO's ECRM. He explained that these costs will no longer be recovered through the ECR Tracker once new rates are implemented, and noted that all MATS compliance costs associated with Bailly have been removed. Mr. Hooper testified that Adjustment OM 4-19SS reflects an increase in the on-going level of O&M expenses associated with NIPSCO's MATS Compliance Project and MPCP Project by $24,124 to reflect the implementation of the proposed service structure and the loss of load associated with NIPSCO's largest industrial customers.

Mr. Hooper testified that Adjustment OM 5-18 and OM 5-19 increase the Historic Base Period by $4,039,088 and 2,384,304, respectively, for budgeted increases in FMCA tracker expense, and that OM 5B-19R increases Forward Test Year operating expenses by $8,344,575 to reflect the ongoing level of O&M expenses associated with NIPSCO's NERC Compliance Project currently being recovered through NIPSCO's FMCA. Upon implementation of new base rates, these costs will no longer be recovered through the FMCA Tracker.

H. Kelly R. Carmichael. Mr. Carmichael testified about the current, major environmental regulations with which NIPSCO must comply and proposed regulations that NIPSCO anticipates will be implemented in the near term. He also addressed how NIPSCO has evaluated the cumulative impact of increasingly complex future environmental requirements on

its resource planning and the increased operating pressure such regulations place on existing coal-fired plants.

Mr. Carmichael explained the environmental drivers for the cost increases that NIPSCO has experienced since its last rate case was filed in 2015. Specifically, NIPSCO has been faced with a number of major environmental mandates, which have and will continue to result in cost impacts to its customers. The most significant of these recent mandates are the EPA's CCR Rule and MATS. He summarized the Environmental Compliance Projects that NIPSCO has implemented leading into NIPSCO's last rate case and the CPCN approved by the Commission in Cause No. 44872, primarily related to compliance with the CCR Rule.

Mr. Carmichael explained the major environmental statutes and regulations and their impact on NIPSCO's operations. The federal environmental statutes with the most significant economic impact on NIPSCO's operations are the Clean Air Act ("CAA") and its amendments, the Clean Water Act ("CWA"), and the Resource Conservation and Recovery Act ("RCRA"). For the CAA, Mr. Carmichael explained that there are numerous recent and anticipated air regulations that affect, or have the potential to affect, NIPSCO's electric generating units. Over the past few decades, the EPA has set increasingly more stringent National Ambient Air Quality Standards ("NAAQS") for particulate matter, ozone, sulfur dioxide ("SO2"), lead, NOx, and carbon monoxide ("criteria pollutants"). These tighter federal requirements generally translate into federal and state requirements that impose additional environmental controls on emission sources. He explained that NIPSCO has incorporated the expected requirements resulting from NAAQS into its planning process, including its 2016 and 2018 IRPs and that each NIPSCO generating unit is equipped with controls to reduce emissions and ambient concentrations of criteria pollutants.

Mr. Carmichael described the Cross-State Air Pollution Rule ("CSAPR"), an emission allowance trading program that establishes SO2 and NOx emission allowance allocations for each NIPSCO generating unit. He also described MATS, which was issued to reduce mercury, other non-mercury metals, and acid gas emissions from coal- and oil-fired generating units, and required compliance at four NIPSCO coal units by April 2015. NIPSCO received a one-year compliance extension from the Indiana Department of Environmental Management ("IDEM") for its other three coal units. Mr. Carmichael testified that NIPSCO is in compliance with CSAPR, as its entire coal-fired generation fleet is equipped with FGD controls for SO2 removal. By implementing NIPSCO's MATS compliance projects approved in Cause No. 44311 in 2013, NIPSCO has also achieved compliance with MATS.

Mr. Carmichael also testified about EPA's "Clean Power Plan" that was issued in 2015 under section 111(d) of the CAA and stayed by the U.S. Supreme Court in 2016, but scheduled to be replaced with the Affordable Clean Energy ("ACE") rule. He noted that the specific ramifications of this rule are not known at this time. Mr. Carmichael explained that NIPSCO did consider the impacts of regulation of greenhouse gas ("GHG") in its 2018 IRP. He stated that the IRP GHG analysis included various carbon reduction outcomes and timing sensitivities. Paired with a range of carbon costs, NIPSCO considered various alternatives, such as: (1) natural gas generators including natural gas combined cycles; (2) renewable energy options; (3) customer EE and DSM; and (4) distributed generation. He testified that the feasibility of the technology or programs, the commercial availability, economic comparisons to other technologies, and

compliance with environmental regulations were all taken into account; however, specific ACE Rule scenarios were not included in the IRP because requirements are not known at this time.

Mr. Carmichael further testified about the CWA, which establishes water quality standards for surface waters as well as the basic structure for regulating discharges into the waters of the United States. Under the CWA, the EPA implements pollution control programs such as setting wastewater standards for industry including for electric utilities. CWA requirements are generally implemented by the National Pollutant Discharge Elimination System ("NPDES") permit program. He explained how CWA regulations impact NIPSCO's operations, including through the Effluent Guidelines and Standards ("ELG Rule"), which was most recently revised on January 4, 2016. The ELG Rule regulates wastewater discharges from power plants that use a fossil fuel to generate electricity and is implemented as the regulatory requirements are incorporated into NPDES permits. He stated that the ELG Rule imposes new wastewater treatment and discharge requirements on NIPSCO's generating facilities applicable between 2018 and 2023. He explained that the requirements of this rule were incorporated into Michigan City's NPDES permit effective April 1, 2016. The ELG Rule itself, though, is under reconsideration by EPA, which anticipates finalizing changes to it in late 2019.

Mr. Carmichael testified about NIPSCO's current compliance with the ELG Rule. Specifically, once certain improvements related to CCR compliance go into service, Schahfer Units 14 and 15 and Michigan City Unit 12 will meet the requirements of the existing ELG Rule for bottom ash transport water. Schahfer Units 14 and 15 operate with a wet FGD system and would likely require significant FGD wastewater upgrades if operated beyond the ELG compliance dates. Michigan City Unit 12 has a dry FGD and will meet the requirements of the existing ELG Rule for both FGD wastewater as a result of a dry FGD system and bottom ash transport water as a result of the CCR compliance project. He noted that NIPSCO's preliminary study estimated ELG Rule compliance costs to be approximately $170 million.

Mr. Carmichael next described RCRA, which sets forth a framework for the management of hazardous and non-hazardous wastes. Under Subtitle D of RCRA, EPA imposed the CCR Rule. The CCR Rule is federally mandated and became effective October 19, 2015, with multiple compliance dates phased in over time. As Mr. Carmichael explained, in 2016 the Water Infrastructure Improvements for the Nation Act amended the CCR Rule and authorized states to submit, to the EPA for approval, a permit program for regulating CCR units in lieu of the CCR Rule. This amendment also allows states to adopt different technical standards from the CCR Rule so long as the standards are at least as protective as the federal rule. In circumstances where a state does not seek approval of a permit program or where EPA denies a state application, the amendments require EPA to adopt a permit program in lieu of the self-implementing rule, provided Congress provides funding for EPA to carry out a permit program. If no permit program is in effect in a state, the CCR Rule remains self-implementing.

Mr. Carmichael also explained that the Indiana Environmental Rules Board adopted a rule incorporating the EPA CCR Rule requirements for CCR surface impoundments into the Indiana Code in 2016 and that IDEM adopted an amendment to Indiana's Solid Waste Management Plan describing IDEM's plan to update regulations regarding CCR disposal facilities to standards equivalent to the CCR Rule in 2017. He stated that this plan enables IDEM to approve and enforce

compliance schedules and to extend deadlines in the CCR Rule under certain circumstances and was approved by EPA on March 7, 2017.

Mr. Carmichael testified about NIPSCO's compliance with the CCR Rule's requirements related to location restrictions, impoundment design criteria, operating criteria, groundwater monitoring and corrective action, closure and post-closure care, and recordkeeping, notification, and posting of information. He explained that NIPSCO is in the process of executing a set of projects, approved by the Commission in Cause No. 44872, to ensure compliance with the CCR Rule. Ultimately, groundwater monitoring results, location restrictions, future CCR management practices, and beneficial use of CCRs will determine compliance outcomes. He explained that, in the near term, NIPSCO is required to install a groundwater monitoring network, containerize CCR processing areas, address inactive CCR surface impoundments, conduct periodic inspections, and create a publicly accessible recordkeeping and reporting internet site. In addition, NIPSCO is currently reviewing data and will update closure plans and assess corrective measures for IDEM review and approval, as required by the CCR Rule and IDEM. In the meantime, NIPSCO continues to meet the compliance obligation established in the final CCR Rule. He also provided cost estimates and other information for the CCR compliance projects approved in Cause No. 44872.

Mr. Carmichael next explained that NIPSCO is not proposing to recover ARO costs through its base rates in this proceeding but that the compliance requirements are mandatory and NIPSCO must expend the necessary funds to ensure compliance. Mr. Carmichael stated that there are certain events that may require CCR surface impoundments to cease operation and close and explained that, based on currently-available groundwater monitoring data, there may be a triggering event that would require NIPSCO to cease placing CCRs into the surface impoundment within six months and initiate closure within 30 days. He testified that the CCR Rule also has an alternative closure provision that allows a CCR surface impoundment to continue to operate if the owner certifies that the facility will permanently cease operation of the boiler and complete closure by October 17, 2023, for a surface impoundment that is 40 acres or smaller, or by October 17, 2028, for a surface impoundment that is greater than 40 acres. He also outlined recent developments to the CCR Rule, including certain litigation and EPA review that is ongoing.

Mr. Carmichael also explained that NIPSCO has a total of 13 CCR surface impoundments and one CCR Landfill at Bailly, Schahfer, and Michigan City that are subject to the CCR Rule and/or RCRA. He explained the two closure methods available to NIPSCO under the CCR Rule: (1) closure by removal; and (2) closure in place (a.k.a., "capping"). Closure by removal entails dewatering of the free liquids within/on top of the ash, followed by excavation of all ash within the pond limits, including the liner if present. The excavated ash is then properly managed, and the pond can then be backfilled and graded. Closure in place entails the removal of the free liquids within/on top of the pond as well as free liquids in materials placed in the pond. Once the pond is dewatered, the remaining CCRs must be graded, and in most circumstances, have additional fill materials brought in to provide a suitable base for the cap. The CCRs are then capped with soil, clay, or an engineered barrier, then mulched and seeded with a vegetative cover. In addition to the cap, there are some indications that a slurry wall or in-situ stabilization may be required for surface impoundments that have a hydraulic connection to the groundwater and are closed in place. Mr. Carmichael outlined the number of CCR impoundments and landfills at each NIPSCO generating station and the currently-anticipated method of closure for each, which are subject to change based on the effectiveness of its closure activities and collection of further groundwater data. He again

noted that NIPSCO is not proposing to recover these federal CCR compliance costs through base rates in this proceeding and that the costs have not been included in the Asset Demolition Studies for each generating station sponsored by NIPSCO witness Ranalletta. As delineated in Mr. Ranalletta's Attachments 12-A, 12-B, and 12-C, federally mandated CCR ARO costs, inclusive of contingency and indirect costs, at Schahfer are expected to be $90.893 million; at Bailly are expected to be $24.736 million; and at Michigan City are expected to be $25.89 million.

Mr. Carmichael outlined other significant environmental remediation obligations at its generating stations. NIPSCO has some coal ash-related remediation obligations that are not directly tied to the federal CCR Rule, which include requirements under Indiana's Solid Waste Management Program. At Bailly, there are also obligations under the federal RCRA that are related to Solid Waste Management Units based on an order entered into between NIPSCO and EPA in 2005 under RCRA, which required NIPSCO to investigate and, if needed, remediate areas at Bailly that were impacted by historic waste handling. He also discussed federal and state obligations related to asbestos containing material at Bailly, Schahfer, and Michigan City.

Mr. Carmichael addressed the interplay between environmental regulation and NIPSCO's resource planning. He testified that NIPSCO incorporates the cumulative impact of future environmental requirements in the IRP process and that the IRP considers impacts of anticipated environmental rules and regulations. Notably, the CCR and ELG Rules require significant capital expenditures for compliance. Future anticipated regulation of GHG emissions and updated CSAPR and ozone NAAQS regulation on Schahfer Units 17 and 18, were also specifically considered.

Mr. Carmichael testified about key assumptions NIPSCO made for environmental regulations that impact the IRP. For the CCR Rule, he stated that NIPSCO is required to incur capital cost for Schahfer Units 14 and 15 and Michigan City Unit 12 of approximately $193 million. Based upon a preliminary study of the November 3, 2015 ELG Rule, capital costs for ELG compliance were expected to be approximately $170 million for Zero Liquid Discharge control technology on Schahfer Units 14 and 15 and $375 million for Units 17 and 18. Michigan City Unit 12 is equipped with a dry FGD and is not anticipated to require any significant capital expenditure for ELG Rule compliance. CCR-related infrastructure investment will allow Unit 12 to comply with other aspects of the ELG Rule by the November 1, 2018 compliance date established in its NPDES permit. He also testified that no capital expenditure is expected for ELG compliance on Schahfer Units 14, 15, 17, and 18 because, based on preliminary 2018 IRP results, NIPSCO anticipates retiring these by 2023. He stated that NIPSCO did consider several possible ELG rulemaking outcomes in the IRP, which include the requirement to install Zero Liquid Discharge ("ZLD") technology or non-ZLD technology, compliance via unit retirement, and extended compliance dates. Regarding GHG reduction, although the timing and magnitude of required reductions are uncertain, it does not appear likely that significant electric sector GHG reductions will be required by regulation or legislation until the year 2026 or later.

Mr. Carmichael testified that, in the IRP modeling, NIPSCO assumed three carbon price scenarios: base, low, and high. The base case assumes a new federal rule or legislative action effective in 2026. The low case assumes a replacement CPP rule with a focus on coal plant efficiency improvements; however, due to the lack of specificity of requirement at present, no direct costs were assumed for these improvements within the IRP. No specific tax or emission cap requirement would be present under such regulations. The high case assumes a stricter new federal

rule or legislative action effective by 2026. He explained that price levels are generally consistent with a 50-60% reduction in electric sector carbon dioxide ("CO2") emissions relative to 2005 by the 2030s. In addition, retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures beyond CCR, ELG, and GHG compliance to reduce NOx emissions. He noted that the IRP assumed compliance with updates to CSAPR and ozone regulations that have not yet been proposed, utilizing SCR technology with a capital cost estimate of $448 million.

I. Andrew S. Campbell. Mr. Campbell explained the purpose of MISO and provided an overview of the MISO Resource Adequacy Process. He explained that NIPSCO, as a Load Serving Entity in MISO, is obligated to have sufficient Capacity Resources to cover its forecasted peak demand plus its Planning Reserve Margin Requirements ("PRMR"). If NIPSCO does not have sufficient Capacity Resources to cover its forecasted peak demand and PRMR, NIPSCO may acquire additional capacity through bilateral transactions with other Market Participants or by bidding on capacity in MISO's annual Planning Resource Auction ("PRA"). If NIPSCO has additional capacity, it may sell the additional capacity in MISO's PRA, or through a bilateral transaction with other Market Participants. Mr. Campbell explained that NIPSCO participates in the MISO Energy and Operating Reserve Market (the "MISO Market"), and offers electricity produced and purchases electricity from the MISO Market on a day-ahead and real-time basis. He explained that participating in the MISO Market provides several benefits, including increased reliability. Mr. Campbell also testified about NIPSCO's MISO-related costs.

Mr. Campbell explained that NIPSCO has two Wholesale Purchase and Sale Agreements for wind energy. NIPSCO is crediting any OSS created by its wind purchase power agreements ("PPAs"). In addition to its PPA wind purchases, NIPSCO recovers cost of capacity and energy purchases made through its Electric Renewable Feed-In Tariff. NIPSCO recovers purchases of energy from eligible renewable resources through its Section 42(a) tracking mechanism, which is filed with its quarterly FAC proceedings consistent with NIPSCO's treatment of its wind PPA purchases approved in Cause No. 43393, and defers the costs of purchases of capacity under the Electric Renewable Feed-In Tariff for recovery through NIPSCO's Resource Adequacy tracker ("RA Tracker").

Mr. Campbell explained NIPSCO's Capacity, including MISO Requirements, Resources, and Cost. He testified that MISO's Resource Adequacy construct ensures adequate capacity. Any proceeds from the sale of excess capacity sold bi-laterally or through MISO's PRA are credited within NIPSCO's RA Tracker. Any excess capacity that is sold, or additional capacity that is purchased by NIPSCO to meet its Resource Adequacy, is recovered in the NIPSCO RA Tracker. Mr. Campbell explained NIPSCO's three Demand Response programs: (1) an interruptible offering under Rider 775 whereby large industrial customers can sign up to offer interruptible service used for both economic and reliability reasons; (2) a Demand Response Resource offering under Rider 781 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy; and (3) an Emergency Demand Response offering under Rider 782 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy for use during emergency operations. He testified that under the proposed rates, NIPSCO will continue to offer three Demand Response programs within Rate 831, Rider 881, and Rider 882. He stated that options within NIPSCO's proposed Rate 831 qualify as a LMR under MISO's tariff, and allows NIPSCO to receive Zonal Resource Credits ("ZRCs").

Mr. Campbell then described proposed Rate 831 – Industrial Power Service – Large. He stated that as proposed, Rate 831 is available to industrial customers currently taking service under Rates 732, 733, and 734. Rate 831 has three tiers of service: (1) Tier 1: Firm Service; (2) Tier 2: Non-Firm Market Price Service; and (3) Tier 3: Non-Firm Third Party Generation Service. He stated that customers must demonstrate or document, to NIPSCO's satisfaction, the ability to reduce demand to the Tier 1 elected level plus additional firm capacity procured, as allowed, under Tier 2 and Tier 3. If a Customer's elected service results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to NIPSCO's satisfaction, that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3. This information will be utilized to register the curtailable demand as an LMR with MISO. The Customer can choose to procure additional capacity to reduce or eliminate its curtailable obligations as an LMR through the PRA or by purchasing capacity through a third-party bilateral agreement.

Mr. Campbell described how NIPSCO will determine a Customer's capacity requirement. He stated that NIPSCO is obligated to have sufficient Capacity Resources to cover its forecasted Coincident Peak demand plus PRMR with MISO. He explained that by September 30 of each year, NIPSCO will share with each Customer its PRMR, forecasted Coincident Peak demand, and supporting documentation. The Customers will have 30 days to review and dispute these values. NIPSCO will make all reasonable efforts to resolve any such disputes; however, as the MISO Market Participant, NIPSCO is responsible for all forecasted needs and its forecast methodology, which is subject to audit and due diligence by MISO. He indicated NIPSCO will submit the Customer's Resource Adequacy Requirements on November 1 of each year to comply with MISO's Resource Adequacy timeline. He summarized that this process results in Customers taking service under Rate 831 covering their load ratio share of NIPSCO's Resource Adequacy Requirements with MISO.

Mr. Campbell then described Tier 1, Tier 2, and Tier 3 service under Rate 831. Tier 1 is a firm service served by NIPSCO's generation and market activity in MISO. The default Contract Demand election is 30,000 kilowatt ("kW") with an option to elect above or below that amount down to 10,000 kW. Tier 1 service is subject to applicable Riders as identified in Appendix A of the tariff. Tier 1 service will be first through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service.

Mr. Campbell explained that the Customer's Tier 2 Contract Demand is the Customer's PRMR using NIPSCO's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 Contract Demand election and any Tier 3 Contract Demand election by the Customer. This service is subject to applicable non-production Riders as identified in Appendix A of the tariff (potential components of FMCA and the energy components of the RTO). The Customer will take all Energy under this Tier 2 service at Day-Ahead LMP at the applicable Company Load Zone plus Transmission Charges. Tier 2 service will be second through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service and then Tier 2 service.

Mr. Campbell testified that Tier 2 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an

LMR at MISO that portion of the Customer's Tier 2 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 2 Contract Demand is non-firm, subject to MISO Curtailment.

Mr. Campbell stated that the Customer may elect a Tier 3 Contract Demand up to the Customer's PRMR using NIPSCO's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 firm Contract Demand election. To the extent a Customer declines to elect the Tier 3 Contract Demand to which it is entitled under this Rate, it must elect to take Tier 2 Contract Demand. If the Customer elects to take any Tier 3 Contract Demand, NIPSCO, as the Market Participant, will register that Customer as an Asset Owner at MISO. Mr. Campbell explained that Tier 3 service is subject to applicable non-production Riders as identified in Appendix A of the tariff (potential transmission related components of FMCA). Tier 3 service will be third through the meter unless services under Rider 876 are being utilized, at which point Rider 876 services will be first through the meter followed by Tier 1 service, then Tier 2 service, and finally Tier 3 service.

Mr. Campbell explained that if, under the MISO Asset Owner framework, a Customer has not arranged for any third-party energy with NIPSCO as the contracting Market Participant, the Customer will take all Energy under this Tier 3 service at market price (LMP at the applicable Company Load Zone plus all applicable MISO market settlement charges plus the Transmission Charge within the Rate). The Customer will be responsible for all market settlement charges incurred by either NIPSCO as the Market Participant or the Customer as Asset Owner for any third-party energy or capacity arrangements including, but not limited to, transmission charges to deliver energy. MISO Market Portal access will be provided as required to carry out MISO Asset Owner functions. All settlements associated with energy offers and demand bids will be passed through to the Customer and will be billed to the Customer on a weekly basis.

Mr. Campbell stated that Tier 3 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of the Customer's Tier 3 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 3 Contract Demand is non-firm, subject to MISO Curtailment.

Mr. Campbell explained the difference between Tier 2 and Tier 3 service under Rate 831. He stated that the primary difference between Tier 2 and Tier 3 is the options each Tier provides for the optimization of demand and capacity in the MISO Market. Tier 2 is essentially a market price service for energy and allows for the "firming-up" of capacity through the MISO PRA or third-party capacity arrangements. Tier 3 increases optionality available for Customers to optimize their demand in MISO. Tier 3 allows the Customer, with NIPSCO acting as the Market Participant, the ability to optimize their demand using available MISO market options. He stated that this could include procuring all or a portion of expected energy needs in the Day-Ahead Market or entering into third-party bilateral energy arrangements (alternative generation). Customers will also be able to procure capacity through the MISO PRA or arrange third-party capacity arrangements. Tier 2 and Tier 3 are similar in the sense that any demand not covered by a capacity purchase will be registered at MISO as a LMR and subject to MISO Curtailment. Furthermore, Tier 2 and Tier 3 are both market-based options that are not backed by NIPSCO-owned generation resources.

Mr. Campbell stated that customers will be able to move demand between Tier 2 and Tier 3. He explained that as proposed in Rate 831, Customers will have the ability to make quarterly adjustments between Tier 2 and Tier 3. Customers are allowed to have both Tier 2 and Tier 3, Tier 2 only, or Tier 3 only. NIPSCO will register a single LMR for any Tier 2 and Tier 3 demand not covered by a capacity purchase at MISO as a LMR. He noted that NIPSCO, as the Market Participant at MISO, is ultimately financially responsible for all the associated activity of its retail customers. While Tier 2 and Tier 3 of Rate 831 do allow degrees of market access, customers taking service are still participating through a retail rate and are subject to charges related to the delivery of energy using NIPSCO's transmission system.

Mr. Campbell said that by creating separate CP Nodes and individual settlement statements with MISO, other customers will be insulated from activity of Tier 3 customers. Furthermore, any additional charges related to the activity of Tier 3 Customers will be passed on to the appropriate party (i.e., transmission charges associated with any out-of-market activity). Mr. Campbell stated that while NIPSCO will be liable for Tier 3 customers' decisions in the MISO Market, the proposed tariff creates a direct link that makes Tier 3 customers wholly responsible for all of the costs associated with their activity in the MISO Market. He explained that the Asset Owner arrangement allows for a clear carve out of the individual customer activity. As such, Tier 3 customers receive the full benefits and risks associated with activity in the MISO Market.

Mr. Campbell addressed how curtailments will change under Rate 831. He stated that any non-firm demand under Tier 2 and Tier 3 that is not otherwise covered by procured capacity will be registered by NIPSCO as an LMR with MISO. There is no change in the obligations associated with the LMR registrations from today under current Rider 775. He added that Rate 831 is written in a way that if MISO's LMR rules change, Tier 2 and Tier 3 customers will be obligated to comply for any non-firm demand.

Mr. Campbell described the curtailment order that NIPSCO will follow. He detailed that ideally, the first set of customers to be curtailed will be Tier 2 and Tier 3 customers since both of these are non-firm unless capacity is arranged otherwise. Second, customers taking service under Rider 876 and Back-Up, Maintenance, and Temporary Services under Rate 830 will be curtailed in the event curtailments under Tier 2 and Tier 3 are insufficient. He stated that it is possible that service under Rider 876 and Back-Up, Maintenance, and Temporary Services under Rate 830 will be curtailed before exhausting curtailments under Tier 2 and Tier 3 depending on the specifics of the curtailment order issued. Addressing curtailment notice requirements, he indicated that NIPSCO will dispatch Customers for MISO curtailments in accordance with the limitations specified under Rate 831 and NIPSCO's General Rules and Regulations.

Mr. Campbell testified that since the start of the MISO Market, none of NIPSCO's customers have been curtailed and that NIPSCO does not anticipate that there is any increased risk of curtailment as a result of the proposed industrial service structure. Unless there is a localized emergency, where NIPSCO can issue curtailments under Rule 13 of its General Rules and Regulations, curtailments are controlled by MISO, and NIPSCO cannot predict the future utilization of curtailments by MISO.

Mr. Campbell indicated that as a result of the new industrial service structure, NIPSCO will alter its participation within the MISO Market. Generally, for Industrial Customers choosing

Tier 3 service, NIPSCO will no longer procure energy nor capacity for their Tier 3 loads. However, for Tier 2 Customers, NIPSCO will procure energy from the market on their behalf. That energy will be allocated to Tier 2 Customers and be priced at the Day-Ahead LMP at NIPSCO's applicable Load Zone. NIPSCO will continue to offer the energy produced by its generation facilities into the MISO Market, and it will continue to purchase the energy necessary to serve its non-Tier 3 retail customers from the MISO Market on a day-ahead and real-time basis. He added that Rate 831 will simply place the burden of optimizing customer specific loads on customers electing service under non-firm Tier 3 and that NIPSCO will continue to optimize remaining retail customer load.

Regarding implementation, Mr. Campbell first noted that an order in this proceeding could result in an implementation date that does not coincide with MISO's Planning Year. He stated that NIPSCO will make reasonable efforts to register interested customers that qualify for Rate 831 service as Asset Owners consistent with MISO's commercial model updates, so that those registrations are available for a day one of the implementation of new rates. He explained that customers with existing LMR registrations will be required to maintain the same level LMR registration (or more) until the start of the next MISO Planning Year unless Replacement Capacity is provided by the Customer. Customers will remain curtailable until firm capacity is procured at which time NIPSCO will transition Customers to the forecasted Coincident Peak demand plus the PRMR method as discussed above to be consistent with the proposed Rate 831. He stated that Tier 3 Customers will be able to arrange third-party/bilateral energy contracts prior to or shortly after an order is issued. Energy contracts do not have any restrictions requiring alignment to MISO's Planning Year, and as such, there is no implementation risk as energy contracts can start and stop in line with the negotiated terms of the contract.

Mr. Campbell provided an overview of the changes proposed in Rider 876 – Back-Up and Maintenance Industrial Service Rider. He stated that Rider 876 is only available to customers taking service under Rate 831. He explained that other changes proposed in Rider 876 include the removal of Temporary Service and an updated pricing structure so it is consistent with Rate 831. He indicated that as an alternative to Back-Up and Maintenance Service under this Rider, a Customer can elect to instead cover the risk associated with derates and outages of its Cogeneration System without risk of Curtailment by utilizing Rate 831 Tier 2 or Tier 3 service and procuring capacity through the MISO PRA or via a third party subject to the provisions outlined in Rate 831. He stated that existing Back-Up and Temporary Service provided in current Rider 776 is retained in NIPSCO's new Rate 830 to align to specific customer needs.

He stated that NIPSCO is also proposing to remove the revenues associated with its Rider 876 due to NIPSCO's inability to predict the usage of the Rider by customers. He explained that the proposed changes to the service structure may alter customer's utilization of proposed Rider 876 and that, services are available under Rate 830, but there still is an inability to predict customer activity. He noted that NIPSCO will also pass back any margins resulting from Back-Up and Maintenance Services through the RTO tracker.

Mr. Campbell stated that as proposed, new Rate 830 – Industrial Power Service – Small is similar to existing Rate 732 and is available to Industrial Customers taking service at Transmission or Sub-transmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Sub-transmission capacity sufficient to meet the Customer's requirements. He explained that Rate 830 differs from Rate 732 in that the Customer shall contract for a definite

amount of electrical capacity which shall be not less than 10,000 kW and not exceed 25,000 kW. He noted that under Rate 732, Customers contracted for a definite amount of electrical capacity that was not less than 15,000 and that existing Rate 732 customers that do not meet the minimum demand threshold are grandfathered into the rate.

He stated that existing Back-Up, Maintenance, and Temporary Services under Rider 776 is retained in Rate 830 to align with Customer specific needs. Customers taking Back-Up, Maintenance, and Temporary Services under this Rate shall be subject to Curtailments when curtailment of NIPSCO's customers under Rate 831 is insufficient. He indicated that except for Buy-Through energy under Temporary Service or Back-Up Service, this Rate shall be subject to other Riders as identified on Appendix A of the tariff.

Mr. Campbell provided an overview of the changes proposed in Rider 881 – Demand Response Resource Type 1 (DRR 1) – Energy Only. He explained that although Rider 881 is largely an updated version of the existing Rider 781, changes were warranted to better align with proposed Rate 830 and Rate 831. He noted that NIPSCO has removed the Marginal Forgone Retail Rate ("MFRR") provisions within Rider 881 to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. He noted that currently, only one customer is actively participating in existing Rider 781.

He stated that NIPSCO is proposing to remove margins associated with its Rider 781 – Demand Response Resource Type 1 – Energy Only (proposed Rider 881). He explained that NIPSCO offers the demand response program to allow NIPSCO's industrial customers a means of offering load drop into the MISO Market as a Demand Response Resource. He stated that the margin NIPSCO receives through Rider 881 is meant to compensate NIPSCO for its MFRR during the load drop event making it appropriate to remove these margins from the Revenue Requirement due to NIPSCO's inability to predict the usage by customers. Mr. Campbell noted that changing market dynamics and individual customer operating characteristics could increase or eliminate the activity. Furthermore, the margin received through the Rider is offset by retail sales that occur should customers choose to discontinue usage of the Rider. He noted that the inability of NIPSCO to predict usage under this Rider and the fact that activity under this Rider is essentially a wash between MFRR and retail sales are both valid reasons that support the removal of margin collected through this Rider. Mr. Campbell sponsored Adjustment REV 16-19SS to decrease the Forward Test Year by $3,383,524 to remove all Demand Response Resource margins.

Mr. Campbell provided an overview of the changes proposed in Rider 882 – Emergency Demand Response Resource Type 1 (EDR 1) – Energy Only. He explained that although Rider 882 is largely an updated version of the existing Rider 782, changes were warranted to better align with proposed Rate 830 and Rate 831. He noted that NIPSCO has removed the MFRR provisions within Rider 882 to better align with MISO's treatment of emergency demand response resources and to reduce potential barriers to customer participation. Currently, no customers participate in existing Rider 782.

Mr. Campbell testified that proposed Rate 831 provides two options of curtailable service: (1) Tier 2 is "curtailments and/or MISO PRA capacity;" and (2) Tier 3 is "curtailments, MISO PRA capacity, and/or third-party capacity," both of which allow a customer to procure capacity to

reduce or eliminate the curtailable portion of its load. He stated that in either circumstance, the load is covered from a MISO Resource Adequacy perspective.

Mr. Campbell explained NIPSCO's change in the Resource Adequacy Adjustment in this proceeding. He noted that NIPSCO is proposing that the charge of $1,500,000 realized through the purchase of capacity and the sale of excess capacity be removed from the Historic Base Year and the Forward Test Year due to the variability of capacity prices in the broader market. Mr. Campbell sponsored Adjustments REV 2-19R and FP 1B-19R to decrease revenue and expense to remove all budgeted capacity purchases from the Forward Test Year.

Mr. Campbell testified regarding NIPSCO's RTO Tracker, including OSS. He explained that OSS occur when NIPSCO's real-time generation resources exceed the real-time native load obligation excluding Rate 831 Tier 2 and Tier 3 activity. The fuel costs associated with making an OSS are passed back to NIPSCO's FAC customers in the form of a fuel credit. He noted that the August 25, 2010 Order in NIPSCO's 2008 electric rate case in Cause No. 43526 (the "43526 Order") found that NIPSCO's MISO non-fuel costs and revenues and OSS sharing should be included in one mechanism designated as the RTO Adjustment. He explained that the MISO charges and credits are included in the RTO Tracker and the basis on which (energy or demand) each is allocated to customers. He stated that the Commission's 44688 Rate Case Order approved recovery of $16,585,108 of MISO non-fuel transmission costs (net of revenues) in base rates, reset the RTO benchmark to recover or pass back any amounts above or below this amount through the RTO Tracker, and reset the OSS margin credit to base rates to reflect the level of OSS margins included in base rates of $4,741,390. Mr. Campbell testified that in this proceeding, NIPSCO is proposing to fully track MISO non-fuel costs (net of revenues) and recover the costs through the RTO Tracker. He explained that NIPSCO is making this change because Rate 831 Tier 2 and Tier 3 customers will be responsible for various charges and will be paid differently than today. He noted that if NIPSCO were to include the charges in base rates, there would be a misalignment unless NIPSCO ran a COSS for each charge type, which would be extraordinarily time consuming.

Mr. Campbell noted that in this proceeding, NIPSCO is also proposing to reset the OSS margin credit to base rates to zero. He explained that with the retirement of Bailly Units 7 and 8, NIPSCO's opportunities for OSS could be reduced. He noted the retirement aligns NIPSCO's supply side resources with its load obligations in MISO and could result in less of an opportunity for OSS. On the other hand, NIPSCO's new industrial service structure could result in opportunities for additional OSS. He testified that given the uncertainties, when OSS do occur, NIPSCO would pass back 100% of the margins back to customers. Mr. Campbell sponsored Adjustments REV 9E-19R and FP 3B-19R to decrease revenue and expense to remove all OSS revenues and fuel expenses budgeted for capacity purchases from the Forward Test Year. Mr. Campbell testified that in this proceeding, NIPSCO is also proposing that 100% of OSS margins would be credited to the customer. He explained that the credit would be determined annually and incorporated into NIPSCO's semi-annual tracker filing. Mr. Campbell testified that in this proceeding, NIPSCO is also proposing to pass back any margins resulting from back-up and maintenance services through the RTO tracker. Like the OSS margins, the credit would be determined annually and incorporated into NIPSCO's RTO Tracker semi-annual tracker. Finally, he added that NIPSCO is proposing to update the allocation.

Mr. Campbell described and supported proposed pro forma Adjustment REV-8A-19R and FP-2-19R. He stated that NIPSCO liquefied less gas in the Historic Base Period (January 1, 2017 – December 31, 2017) compared to the volumes expected going forward. The five-year average of actual gas liquefaction was 1,166,142 MCF. NIPSCO believes the five-year average is an accurate estimate of future liquefaction compared to the 611,701 MCF that occurred during the Historic Base Period. Because the liquefaction process is a heavy consumer of electricity, the volume of gas liquefied creates variations in inter-company electric revenues and the associated fuel costs. Adjustments REV 8A-19R and FP 2-19R increases the Forward Test Year revenue by $1,272,135 and expense by $313,541 to align the budget with a five-year average for gas liquefaction volumes.

J. Susanne M. Taylor. Ms. Taylor provided background on the relationships between NCSC and NIPSCO. She supported the O&M expenses associated with the Corporate and Operating services provided by NCSC to NIPSCO, and she sponsored adjustments to those expenses for the Historic Base Period, 2018 Budget Period, and the Forward Test Year. Ms. Taylor explained the structure and role of NCSC. She testified NCSC was established to provide centralized services to its affiliates because providing services on a centralized basis enables the affiliates to realize benefits, including use of personnel and equipment. She stated there are two types of billings made to affiliates, including NIPSCO: (1) contract billing; and (2) convenience billing. Contract billings represent NCSC labor and costs billed to the respective affiliates and are identified by billing pools. She explained that contract billed charges may be direct-billed (billed directly to a single affiliate or function, including NIPSCO Electric, NIPSCO Gas, or NIPSCO Common), or allocated (split among several affiliates), depending upon the nature of the expense. She also explained that convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees with each affiliate billed for its proportional share of the payments made per month. NCSC makes the payment to the vendor, and the charges for the services are recorded directly on the affiliate's books.

Ms. Taylor testified NCSC has executed an individual Service Agreement with each affiliate that is routinely updated so that all affiliates that receive service from NCSC are subject to the same Service Agreement, which designates the types of services to be performed and the method of calculating charges. She stated NCSC is not responsible for appropriately assessing the split between costs attributable to NIPSCO's Electric and Gas operations unless the costs are directly billed to NIPSCO Electric or NIPSCO Gas, which NCSC started on January 1, 2009.

Ms. Taylor testified NCSC is regulated by FERC. Pursuant to FERC Order No. 684, centralized service companies like NCSC must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with FERC, NCSC uses a billing pool system to collect costs that are applicable and billable to affiliates, including NIPSCO. Costs are directly charged to a particular affiliate whenever possible, and in cases involving more than one affiliate, the billing pool system details how expenses are allocated among the participating affiliates. Ms. Taylor testified NCSC allocates costs for a particular billing pool in accordance with the bases of allocation filed annually with FERC, and noted that descriptions of each basis of allocation is provided in each service agreement. She explained that NCSC currently updates the statistical data used in the approved allocation bases at least on a semi-annual basis

and provides NIPSCO's leadership team the opportunity to review, discuss, and provide feedback prior to publishing the new allocation percentages.

Ms. Taylor testified that system controls are in place to restrict the use of billing pools to companies benefitting from the services being provided. She noted that NIPSCO's Internal Audit group conducts an annual review of cost allocation procedures and makes recommendations related to contract and convenience billing processing. Ms. Taylor noted that NiSource, including NCSC, underwent a FERC audit, Docket No. FA11-5-000 covering the period January 1, 2009 through December 31, 2010, which issued no adverse comments to NCSC related to its allocation methods. She stated that NCSC continues to use the allocation methods subject to that FERC audit.

Ms. Taylor testified all services are provided at cost, including compensation for use of capital. She stated affiliates have the right to meet with NCSC to review and assess the quality, costs, and/or allocations of the services being provided. The NIPSCO accounting team performs a review of the bill and makes selections to review charge details for reasonableness and accuracy and alert NCSC accounting if they disagree with a charge.

Ms. Taylor testified the NCSC budget development process are consistent with the NIPSCO planning process from a timing and planning standpoint. She explained that the budget process used to develop the Forward Test Year was the 2018 AFP, consisting of a five-year horizon where the first two years were broken down by month, and the balance was completed on an annual basis. She stated targets for the NCSC functions are grounded in a trailing 12-month historical spend with merit and inflation adjusted for each year thereafter. The 12-month historical spend is also adjusted to account for one-time items, future planned work, or strategic initiatives.

Ms. Taylor also provided details about the processes that drive the derivation and approval of NCSC budgets. She testified in detail about the substance and calculation of the NCSC O&M expenses allocated to NIPSCO Electric: (1) in the Historic Base Period of $106,556,125; (2) in the 2018 Budget Period of $108,514,206; and (3) in the Forward Test Year of $98,973,383. She supported Adjustment OM 7-17 to reduce Corporate Incentive Payout expenses in the amount of $2,623,753 to reflect a payout consistent with target levels included in the Forward Test Year, and Adjustment OM 7-19R to reduce NCSC O&M expenses in the amount of $10,129,461 to reflect: (1) customer value savings for a decrease of $4,700,000; (2) other ratemaking adjustments for a decrease of $4,732,776 including: LTIP and profit sharing, promotional advertising, and other adjustments that NIPSCO is not seeking to recover; (3) net pension and medical benefit increase of $203,613; (4) 2017 historical actual allocation adjustment between NIPSCO Electric and Gas for a decrease of $741,022; and (5) a NCSC allocation adjustment of $159,276 to reflect updated NCSC semi-annual allocations billed to NIPSCO as of August 1, 2018, and related decrease to NIPSCO Electric.

Ms. Taylor detailed the calculation of the Forward Test Year level of O&M expense, and testified that amount is reasonable and representative of NIPSCO's ongoing cost of providing service. She explained that The Forward Test Year level of O&M expense is justified by the projected needs of NIPSCO to serve its customers.

K. Kimberly K. Cartella. Ms. Cartella testified about the reasonableness and competitiveness of NIPSCO wages and salaries, incentive compensation, and benefits provided to

employees. She also testified in support of the pro forma adjustment to test-year expenses relating to incentive compensation. She explained that NiSource has a "total rewards" compensation philosophy that aims to compensate employees competitively in comparison to the utility industry. According to Ms. Cartella, this compensation philosophy enables NIPSCO to meet its obligation to provide safe, reliable, and cost-effective service to its customers and is consistent across the NiSource companies. She further testified that NIPSCO's total rewards program includes: (1) market-driven base compensation; (2) market-driven performance adjustments/merits; (3) long- and short-term incentives; (4) profit sharing; and (5) health and welfare benefits.

Ms. Cartella explained that NiSource employs compensation and benefits consultants to assist in determining employee compensation across the NiSource Operating Companies. Mercer LLC assists NiSource in setting competitive salary ranges and in evaluating and recommending changes to employee health and welfare benefit plans. Aon Hewitt Associates assists NiSource in pension plan and post-retirement medical actuarial analysis, and Alight Solutions assists with administration of pension and health and welfare benefits.

Ms. Cartella discussed the Corporate Incentive Plan for NiSource and NIPSCO and the annual review, or Performance Management Worksheet, process. The potential to earn incentive pay is needed for NIPSCO to be effective in recruiting, retaining, and motivating its employees. She also explained the three levels of incentive compensation – trigger, target, and stretch – and that NIPSCO's Forward Test Year is based on a "target" level payout. In Attachments 11-A, 11-B, and 11-C, Ms. Cartella provided comparative analyses that demonstrate the reasonableness of NIPSCO's total cash compensation to employees.

Ms. Cartella also testified about the collective bargaining agreements ("CBAs") that are in effect with NIPSCO bargaining units, including how base pay is calculated and the required wage increases under those CBAs. She provided similar information for employees who are not covered by CBAs. In Attachment 11-D, Ms. Cartella provided information about how annual base pay increases at NIPSCO compare to those provided by other employers. She also described the post-retirement benefits other than pensions that NIPSCO provides to its retirees.

Ms. Cartella explained the benefits offered by NIPSCO. These benefits include health and welfare plans, a defined benefit pension plan (for certain employees), a 401(k) savings plan, and paid time off. She stated that benefits are an important component of any compensation structure and are necessary to ensure NIPSCO is able to attract and retain qualified employees. She also testified about steps NIPSCO has taken to manage its health care costs.

Ms. Cartella testified that NiSource has compared benefits NIPSCO offered to other energy companies and that the results of the most recent study performed by Aon Hewitt Associates demonstrated that the overall, employer-paid value of NIPSCO's benefits plans is 3.1% lower than the average of a comparator group of 11 national utility companies. Finally, she concluded that NIPSCO's benefits are competitive and reasonable as compared with the offerings from other comparable utility companies in the labor market.

L. Victor F. Ranalletta. Mr. Ranalletta testified about the results of studies performed by Burns & McDonnell estimating the cost of demolishing and remediating certain NIPSCO Electric generating stations (collectively, "demolition cost"). Mr. Ranalletta explained

that Burns & McDonnell was engaged by NIPSCO to update the prior studies that were performed for NIPSCO in Cause Nos. 43526 and 44688, and to prepare written reports documenting the results for this Cause. He testified that he supervised and directed the studies and personally inspected each generating station for which demolition cost studies were completed. Mr. Ranalletta prepared separate reports for Schahfer (Attachment 12-A), Bailly (Attachment 12-B), Michigan City (Attachment 12-C), and Sugar Creek (Attachment 12-D). He also prepared a demolition cost breakdown for each of the station sites to show what the costs would be if NIPSCO were to include costs related to the AROs.

Mr. Ranalletta described how Burns & McDonnell performed its studies of the demolition cost for NIPSCO's generating units and remediating the sites to industrial condition. Burns & McDonnell first determined the quantities of concrete, structural steel, equipment, electric cable and raceway, conveyors, tanks, and piping that would need to be removed. Burns & McDonnell based the industrial demolition cost estimates on demolishing each plant down to the surrounding grade elevation. Burns & McDonnell assumed all equipment and material located above and below grade would be dismantled and either sent to a landfill or sold as salvage. The estimate also assumed all below-grade foundations would remain and the below-grade excavated areas would be used for landfill space for demolished plant concrete. Mr. Ranalletta testified that Burns & McDonnell did not apply any escalation factor beyond January 2018 to the demolition cost estimates; rather (unless noted otherwise) all of the estimates are in January 2018 dollars. He testified Burns & McDonnell prepared the demolition cost estimates using standard and accepted estimating techniques consistent with available data and industry experience, and that the assumptions listed in each report are reasonable and the estimates are accurate based on the assumptions made. The demolition cost includes environmental remediation, indirect costs, contingency, and positive salvage value. Burns & McDonnell estimated the total net cost to demolish each station, net of positive salvage and excluding costs related to the AROs, to be:

Station	Industrial Condition
Schahfer	$85,070,000
Bailly	$40,643,000
Michigan City	$41,519,000
Sugar Creek	$3,490,000

M. John J. Spanos. Mr. Spanos testified about the depreciation analysis he performed related to NIPSCO's electric plant as of December 31, 2017, and his recommendation of depreciation rates for its forecasted electric and common plant in service as of December 31, 2019. He explained the depreciation study's methods and procedures and sponsored Attachment 13-B setting forth the results of that study (the "Depreciation Study"), Attachment 13-C setting forth the results of his depreciation analysis related to NIPSCO's projected electric and common plant in service as of December 31, 2019, and Attachment 13-D setting forth alternative depreciation rates and expense as of December 31, 2017, and December 31, 2019.

Mr. Spanos provided the principal conclusions of his study and the bases for them. He testified that the proposed depreciation accrual rates by account are based on his review of historical data, NIPSCO's operating maintenance practices, and the application of informed

engineering judgment. He testified that in preparing the depreciation study, he followed generally accepted practices in the field of depreciation and valuation.

Mr. Spanos testified that he used the straight line remaining life method of depreciation, with the Equal Life Group procedure. He explained that this method of depreciation aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational method. His recommended annual depreciation accrual rates as of December 31, 2017, for NIPSCO's electric plant and common plant are set forth in the Depreciation Study.

Mr. Spanos testified that he determined the recommended annual depreciation accrual rates in two phases. In phase one, he estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In phase two, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Regarding the first phase, the service life and net salvage studies consisted of compiling historic data from records related to NIPSCO's plant; analyzing this data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to determine average service life and net salvage characteristics. The historic data analyzed by Mr. Spanos for the purpose of estimating service life characteristics consisted of NIPSCO's accounting entries that record plant transactions during the 82-year period from 1936 through 2017. The transactions analyzed included additions, retirements, transfers, and the related balances. NIPSCO records analyzed also included surviving dollar value by year installed for each plant account as of December 31, 2017. Mr. Spanos used the retirement rate method for all electric and common accounts for NIPSCO to analyze this service life data. He testified that this is the most appropriate method when aged retirement data are available because this method determines the average rates of retirement actually experienced by NIPSCO during the study period.

Mr. Spanos testified that he used the life span technique to estimate the lives of significant facilities such as production plants. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates. He noted that the life span technique has been presented to and accepted by many public utility commissions including the Indiana Commission. Mr. Spanos testified that the bases for the probable retirement years are life spans for each facility that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook, and typical life spans experienced and used by other electric utilities for similar facilities. He further testified that he conducted field reviews of a representative portion of NIPSCO's property in July 2015, and that he had previously conducted field reviews in March 2008.

Mr. Spanos testified that he estimated the net salvage percentages based on judgment. He explained that for most accounts, he incorporated analyses of the historical data for the period 1984 through 2017 for electric plant and considered estimates for other electric companies. He also testified that he factored in final net salvage in his recommended net salvage percentages. He noted that the final net salvage or dismantling costs of steam and other production units were based on

the 2018 asset demolition studies performed by Burns & McDonnell. Mr. Spanos explained that he assigned sufficient depreciation reserve to the Bailly Units 7 and 8 to account for the level of recovery to be fully accrued for these units by December 31, 2019. As a result, no future depreciation expense beyond December 31, 2019 will be assigned to these units.

Regarding the second phase of the depreciation study, in which he calculated the composite remaining lives and annual depreciation accrual rates, Mr. Spanos testified as to the following steps. After he estimated the service life and net salvage characteristics for each depreciable property group, he calculated the annual depreciation accrual rates for each group based on the straight line remaining life method using remaining lives weighted consistent with the Equal Life Group procedure. The annual depreciation accrual rates were developed at December 31, 2017. He explained that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life. He further explained that the Equal Life Group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each Equal Life Group and dividing by the sum of the whole life annual accruals. Mr. Spanos testified that amortization accounting was applied to accounts with a large number of units but with small asset values. He noted that amortization accounting was approved in the 43526 Order and continued in the 44688 Rate Case Order as being appropriate for certain common and general plant accounts, which represents slightly more than 1% of depreciable plant.

Mr. Spanos explained his calculation of the forecasted depreciation rates as of December 31, 2019. First, the plant in service and book reserve were brought forward from December 31, 2017 to December 31, 2019 based on the capital budget by account and by year. The book reserve by account as of December 31, 2019 was developed by adding the annual accruals and gross salvage each month and subtracting retirements and cost of removal each month for the two-year period. Once the plant in service as of December 31, 2019 was developed by vintage within account and the book reserve is developed by account, then the December 31, 2019 depreciation rates were calculated using the same methods and procedures as in the 2017 Depreciation Study. He noted that annual depreciation accrual rates for steam assets at Michigan City and Schahfer are based on the recovery period of December 31, 2030, which is after the retirement date two and seven years, respectively.

Mr. Spanos also calculated alternative December 31, 2017 and December 31, 2019 depreciation rates (set forth in Attachment 13-D) because the steam assets at Michigan City and Schahfer are to be retired by December 2028 and December 2023, respectively. The alternative depreciation rates represent recovery of the full-service value of these assets (including costs related to certain AROs that must be performed in compliance with the federal CCR rule) by the date of retirement, which is prior to the Depreciation Study calculations.

N. Michael D. McCuen. Mr. McCuen testified about and supported NIPSCO's federal and state income tax expense adjustments and the adjustments for taxes other than income taxes between the Historic Base Period and pro forma results based on current rates included in the cost of service shown in Ms. Shikany's accounting exhibits. He also presented and supported

NIPSCO's ADIT and Post 1970 Investment Tax Credit ("ITC") balances and related pro forma adjustments included as components of NIPSCO's Capital Structure.

He explained that the income tax calculations were made under the provisions of the Internal Revenue Code of 1986, as amended, and the Indiana Administrative Code. He stated that the federal tax rate in effect for the Historic Base Period was 35% and that the pro forma test period reflects a 21% federal tax rate in effect starting January 1, 2018. Mr. McCuen testified that he quantified the federal income tax expense beginning with the application of the federal income tax rate applied to pro forma NOI before income taxes less interest expense. He then adjusted this amount to account for: (1) differences between the use of accelerated appreciation for income tax return purposes and straight-line depreciation in determining tax expense for book purposes and AFUDC; (2) various tax rate changes including the most recent TCJA; (3) certain limitations on the amount of the federal income tax deduction that may be taken on certain categories of expense; (4) reduction in tax expense for amortization of ITC; and (5) reduction in tax expense for allocation of parent company (NiSource) interest expense.

For state income tax expense, Mr. McCuen testified that the tax calculations include Indiana Adjusted Gross Income taxes calculated at 5.625%, adjusted for the following four reconciling items: (1) the non-deductibility of the Indiana URT; (2) the excess deferred taxes resulting from the decrease in the state tax rate from 8.5% to 5.625%; (3) the non-deductibility of certain expenses; and (4) AFUDC.

Mr. McCuen explained NIPSCO's proposal to reflect $26,870,010 in real and personal property taxes and explained in detail the calculation of and basis for Adjustment OTX-1 that resulted in a pro forma adjusted property tax expense of $26,870,010 for the Forward Test Year. He stated these pro forma property tax adjustments are required to account for planned property additions between the Historic Base Period and Forward Test Year.

Mr. McCuen explained NIPSCO's proposal to reflect no URT in base rates and explained Adjustment OTX-4 that resulted in pro forma adjusted URT of $0 for the Forward Test Year. He explained that NIPSCO is subject to a 1.4% URT on all receipts, except sales for resale and sales to federal government agencies. The URT is calculated then grossed-up and accounted for in the revenue requirement. He explained that NIPSCO proposes to separately state URT as a line item on customer bills, thereby eliminating the gross-up. He testified that the estimated benefit to NIPSCO's customers in this filing is approximately $500,000.

Mr. McCuen also explained NIPSCO's proposal to reflect $55,856,537 in federal and state income taxes and explained Adjustments ITX 1-19R in the amount of $87,484,708, ITX 1-19SS in the amount of $131,669, and PF4 in the amount of $28,247,441. He explained the federal and state income taxes for the Historic Base Period per books was $114,962,135. The three adjustments were made to the Historic Base Period to: (1) decrease to federal and state income taxes to reflect tax expense on pro forma taxable income at current rates; (2) increase to tax expense due to the changes in the proposed service structure at current rates; and (3) increase to total federal and state income tax due to the increase in proposed revenue requirement.

Finally, Mr. McCuen also explained adjustments to NIPSCO's capital structure. He explained Adjustments CS 4-18 in the amount of $71,828,337 and CS 4-19 in the amount of

$44,252,216 increase Deferred Income Taxes for the period ending December 31, 2018 and December 31, 2019. He stated the deferred income tax balances are forecasted by using a combination of pre-tax income and changes in balance sheet accounts. NIPSCO utilizes Accounting Standards Codification 740 and 980 to account for income taxes in order to reflect its after-tax financial position in its balance sheet. He explained that Adjustments CS 7-18 in the amount of $259,068 and CS 7-19 in the amount of $656,208 decrease Post 1970-ITC for the period ending December 31, 2018 and December 31, 2019. He stated the Post 1970-ITC balances are forecasted by amortizing the remaining balance over the service life of the property that generated the credits, and testified that the tax expense adjustments reflected in Ms. Shikany's accounting exhibits were correct and consistent with his description of the applicable tax provisions.

O. Vincent V. Rea. Mr. Rea testified about the appropriate rate of return on common equity and overall rate of return that the Commission should establish for NIPSCO Electric in relation to its revenue requirement calculation. He also addressed the appropriate ratemaking capital structure, WACC, and embedded cost of debt. Based on his evaluation, he concluded that the cost of common equity for NIPSCO's jurisdictional electric utility operations is in the range of 10.55% to 11.05%, and that a point estimate at the midpoint of this range, or 10.80%, is the appropriate cost of equity to apply in this case. Based upon this finding, he determined that NIPSCO's WACC is 7.02%, which is based on NIPSCO's forward test-year-end regulatory capital structure as of December 31, 2019. This resulting overall cost of capital, if adopted by the Commission, will allow NIPSCO to earn the prevailing opportunity cost of capital, maintain its financial integrity, and attract capital at reasonable terms. Mr. Rea also presented the capital structure and WACC as of December 31, 2019.

Mr. Rea explained the general approach taken in determining the cost of common equity, and supported it with a detailed explanation of the analytical models used and their specific application for this case. He stated that he analyzed market-derived data and other financial information for 18 companies comprising two separate proxy groups. He explained that during the course of his evaluation, he applied three well-recognized analytical models to the market and financial data of the selected proxy group companies: the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), and the Risk Premium Method ("RPM"). He also evaluated two other model variants of the CAPM, specifically, the CAPM with size adjustment, and the Empirical CAPM. Finally, to confirm the reasonableness of the cost of equity estimates yielded by these market-based models, he reviewed the earned returns of non-rate-regulated companies having comparable risks by completing a Comparable Earnings Approach analysis. Mr. Rea developed his cost of equity recommendations after evaluating the individual cost of equity estimates that were derived from applying the various analytical models to the market and financial data of the proxy group companies. Using a variety of analytical models in conjunction with multiple comparable risk proxy groups ensures that a diversity of investor perspectives are incorporated into the cost of capital evaluation, thus providing a solid foundation upon which the analyst can apply his/her informed judgment in making a cost of equity recommendation.

Mr. Rea testified that NIPSCO is proposing that its Forward Test Year capital structure, as of December 31, 2019, be employed for rate-setting purposes. His specific recommendations were presented in Schedule 2, detailing NIPSCO's projected capitalization levels, corresponding capital structure ratios, and embedded cost of debt. To confirm the reasonableness of NIPSCO's Forward Test Year capital structure, he evaluated the actual and projected equity capitalization levels for

the Electric Utility Group companies, as published by Value Line, which are calculated on the basis of permanent capitalization, and therefore exclude short-term debt. He stated that NIPSCO's proposed equity capitalization level, based upon investor-supplied sources of capital, as of December 31, 2019, is 57.11%, which is within the range of equity capitalization ratios anticipated for the Electric Utility Group companies, as reflected in near-term forecasts published by Value Line. Mr. Rea testified the cost rate for common equity is 10.80%, which is the cost of equity he is recommending in this proceeding and the cost rate for Long-Term Debt is 4.97%, which is based on NIPSCO's projected long-term debt outstanding at December 31, 2019.

P. Paula Strauss. Ms. Strauss explained how the Historic Test Period kWh consumption was adjusted to reflect the kWh consumption under normal weather conditions, the baseload temperature-sensitive load normalization procedure, and the forecast method used to derive the Forward Test Year customer counts and volume and to propose an adjustment to align the forecast with the definition of normal weather proposed for ratemaking purposes. She testified that NIPSCO used the baseload/temperature-sensitive load normalization procedure approved in the 44688 Rate Case Order using three sources of data in its analysis: (1) monthly billing data from its actual billing records; (2) NOAA National Weather Service Weather Stations data for actual temperatures used to calculate Cooling Degree Days ("CDD"); and (3) the 30-year average of temperature data from 1988-2017 using NOAA's National Weather Service temperatures. She explained that NIPSCO has updated its definition of normal weather as the 30-year average ending in 2017, which is an update to the normal CDDs calculated by NOAA's National Weather Service, which uses data for the 30-year period ended 2010, using data from Valparaiso, South Bend, and Fort Wayne weighted by the number of residential customers assigned to those stations.

Ms. Strauss testified that with actual CDD lower than normal by 6%, the Historic Test Period was cooler than normal, and usage for the adjusted rates was adjusted up by 0.8% to reflect normal weather which were used by NIPSCO witness Westerhausen to calculate pro forma expense and revenue levels. She explained in detail how kWh usage varied with CDD and explained that in her opinion the data supported the result reached in her study because of the strong correlation between CDD and kWh during the period 2008 through 2017. She concluded that the net result of her analysis was that Historic Test Period volumes should be increased by 59,151,141 kWh to reflect normal weather as reflected in Attachment 16-A.

Ms. Strauss explained that customer and energy projections utilized in NIPSCO's budget are developed by NIPSCO's Forecasting Group using projections of residential and commercial new customer additions provided by the New Business department, budget projections for large industrial customers provided by the Major Accounts department, and an outlook for all other small industrial customers utilized in the budget provided by the Financial Planning department. She testified that the Forecasting Group uses average saturation and efficiency data, economic variables and deflator information, and weather data obtained from external consulting services when estimating the Forward Test Year level of usage. Ms. Strauss provided descriptions of the derivation process used to develop each input into the forecast used to develop NIPSCO's budget. She explained that the forecast was provided to Mr. Westerhausen as reflected in Attachment 16-B to her testimony, and noted that forecasts are updated annually with the most current data. She explained that internal reviews of the forecast performance occur regularly and variances are calculated and assessed in order to measure accuracy. She testified that for the last five years, the

average annual one-year weather normalized variance is 1.8% for the residential model, 1.5% for the commercial model, and 3.8% for the more volatile industrial model.

Q. Bickey Rimal. Mr. Rimal testified in support of the ACOSS used in conducting NIPSCO's electric COSS. Mr. Rimal supported the various special studies that were utilized within the ACOSS to apportion the various categories of plant and O&M expenses to the respective customer classes. Some of these special studies include the Functional Split Study, which consists of analyses that provide the functional split for costs relating to the Sub-transmission, Railroad, Primary, and Secondary functions. He also supported a minimum system study to separately classify certain distribution costs as demand-related and customer-related. He also provided the basis for several studies including the asset allocation study, which allows for the appropriate assignment of assets to different rate classes, and the methodology of the Transformer, Services, and Meters Asset Allocation Analysis. Mr. Rimal described the general need for, and methodology of, the special studies related to NIPSCO's ACOSS. He stated that two main sources of the data and inputs were utilized: (1) the historical books and records of NIPSCO including the general ledger and engineering systems; and (2) interviews with relevant NIPSCO personnel. Mr. Rimal also supported a fixed-variable analysis to determine the proportion of NIPSCO's production O&M that varies with energy consumption. Mr. Rimal also provided basis for allocating certain customer accounts expenses to the various rate classes by conducting Operating Expense Allocation Study.

R. J. Stephen Gaske. Dr. Gaske testified that NIPSCO requested that Concentric conduct a fully-ACOSS to determine the embedded costs of serving its various electric retail customers and design rates that would be reasonable and appropriate for recovering the test-year revenue requirements. Dr. Gaske sponsored the class COSS and rate design, and he stated that the restructured industrial rate and service offerings are reflected in the ACOSS model.

Dr. Gaske discussed the purpose of an ACOSS and described the Concentric Cost of Service Model used in conducting NIPSCO's electric COSS. Dr. Gaske testified that the purpose of the ACOSS is to allocate NIPSCO's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total cost of service (i.e., total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Dr. Gaske discussed various cost allocation principles, factors influencing the cost allocation framework, and the methodology and basis used in NIPSCO's COSS. He noted that Customer Costs are incurred to extend service to and attach a customer to the distribution system, meter electric usage, and maintain the customer's account. Customer Costs are largely a function of the number of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, line transformers, services, meters, and customer billing and accounting expenses.

Dr. Gaske and Mr. Rimal also described the relative cost studies and other analyses employed to apportion the various categories of plant and O&M expenses to the respective customer classes. Dr. Gaske further explained that Demand Costs are capacity-related costs

associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, larger transformers, and substations, or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. He also explained that Energy Costs vary with the amount of kWh sold to customers. For example, base fuel rates and some production operating costs that tend to vary with the amount of energy produced are included in the COSS. However, except for fuel, the vast majority of NIPSCO's costs are fixed with respect to energy usage and very little of its remaining delivery service cost structure is energy related.

Dr. Gaske sponsored attachments and workpapers that showed how NIPSCO's costs were functionalized, classified, and then allocated to the various rate classes. Dr. Gaske discussed the coincident peaks during the four summer months of the test period ("4CP"), June through September, which were used to allocate the demand-related costs associated with the production functions. However, the 4CP demands of the new Rate 831 industrial classes were reduced to reflect the revised firm contract demands that these customers will place on the NIPSCO generating station after their services are restructured. The coincident peak demands that customers placed on the transmission system during each of the 12 months of the test period ("12CP") were utilized to allocate demand-related costs associated with the transmission functions. However, the 12CP demands used in the transmission cost allocation reflect a reduction to the Rate 831 demand to account for the proposed discount for Adjacent Qualifying Facility short-haul transmission service. Dr. Gaske explained that he reviewed the system peaks for all months during the 2010 – 2017 period and applied FERC's cost allocation tests to NIPSCO's load characteristics. Those tests indicated that either a 4CP or a 12CP methodology would be appropriate for the production function. Dr. Gaske noted that after reviewing several years of data, there were ambiguous results for the FERC tests for using a 12CP allocator. He explained that the 2017 results failed one of the FERC tests and 2016 failed two of the three tests. Dr. Gaske further noted that during the past eight years, the months of June – September were almost always within 90% of the annual peak, but none of the other eight months were ever within 90% of the annual peak. Thus, it is appropriate to use a 4CP allocator for NIPSCO's demand-related production costs in this proceeding.

Dr. Gaske described other adjustments to the test period demand and energy determinants. He explained that the generation kWh and 4CP demand allocators used to allocate production costs to these customers (Rate 831) was adjusted to reflect the customers' new generation contract demand and energy use rather than their historical demands. He testified that the 12CP and non-coincident peak demand allocators continue to reflect the actual demands that each class places on the transmission and distribution system with one exception – one large customer decided to recategorize an exempt wholesale generation facility that is owned by an affiliate as behind-the-meter cogeneration. To address this issue and similar possibilities, NIPSCO is offering an alternative transmission charge solely to commonly-owned or affiliated customers that are located on adjacent premises that have cogeneration facilities that can produce power at one premise and transfer that power to its adjacent premise. He stated that because such customers will need to use only a small portion of the NIPSCO transmission system to transmit power from one of its facilities to an adjacent industrial facility, and because some fixed cost contribution is better than none, NIPSCO is proposing to provide a 70% discount on the transmission charge for power that is transmitted between two premises that satisfy the requirements. He testified the 12CP value used to allocate transmission costs has been adjusted to reflect such a discount for these situations.

Dr. Gaske provided class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS for: (1) the 700 series rate classes that were forecasted to be in effect during the test year; and (2) the proposed 800 series rate classes, which included the resulting unit costs by class for customer, demand, and energy-related costs within the ACOSS. Dr. Gaske also described the method used to apportion NIPSCO's revenue deficiency to the various rate schedules. Specifically, he described the principles and methods used to mitigate the impacts on those classes that would receive larger rate increases if the unmitigated results of the ACOSS were used to set rates in this proceeding.

Dr. Gaske testified that NIPSCO used the results of the ACOSS as a first step in deciding the class revenue responsibility. He explained the ACOSS results were then adjusted to mitigate the largest rate increases. Specifically, because of residential class subsidies that were retained in prior rate proceedings, and because of the combination of industrial service restructuring and other cost increases, the ACOSS indicated that residential customers would require a rate increase in excess of 30%. He stated that in order to mitigate this impact, it was determined that all classes except the large industrial (Rate 831) should receive the same across-the-board percentage rate increase. He indicated that rates for the large industrial class would then be based on the allocated cost of service.

Dr. Gaske described the process and showed the calculations used to design the proposed rates. For the new classes, proposed Rate 830 would be a two-part rate consisting of a demand charge and a flat energy charge, and proposed Rate 831 for partial-requirements industrial customers will consist of a demand charge based on the customer's firm contract demand for NIPSCO generation, a transmission charge per kWh of energy it has delivered regardless of generation source, and an energy charge per kWh for energy that is purchased from NIPSCO. He noted that there also is an Adjacent Premise Qualifying Facility discounted transmission rate available. The rate designs for the other classes would remain unchanged.

Dr. Gaske discussed the impact of NIPSCO's proposed removal of the Interruptible Rider (Rider 775). As a result of the restructuring of industrial service offerings, there will no longer be any industrial customer loads taking interruptible service. He stated that projected revenue at current rates includes approximately $52 million in Rider 775 interruptible credits for industrial customers that would be allocated for recovery from all customers but that the industrial restructuring will eliminate those credits and recovery amounts. As a result of the revisions to NIPSCO's Back-up, Maintenance, and Temporary Services available under Rider 776, he noted that the existing Back-Up and Maintenance services under Rider 776 are retained for Rate 830 and Rate 831 customers, and Temporary services are retained for Rate 830 customers. He stated that because 831 customers will manage much of their own generation needs, Temporary service will no longer be available to customers that migrate to that rate schedule. He explained that the rate for Back-up service will continue to be the applicable demand charge divided by the number of days in the month, plus an energy charge equal to the real-time LMP and the non-fuel energy charge. The current daily demand charges for Maintenance service will be increased by the proposed system-wide percentage increase in margin, and the energy and transmission charges for that service would be the energy and transmission charges for the applicable rate schedule. Finally, no change to the existing daily demand charges for Temporary service is being proposed. He stated that because the revenues associated with the proposed Rider 876 are expected to be small and inherently unpredictable, NIPSCO has not included a credit for these revenues in designing the

base rates. Instead, any margin revenue collected under Rider 876 will be flowed through the RTO rider (Rider 871) as a credit on customers' bills.

Dr. Gaske concluded by discussing customer impacts of the proposed rates. He determined that the proposed rate levels and structure establish rates that are just, reasonable, and not unreasonably preferential or discriminatory. Dr. Gaske opined that the proposed rate structure and rates should provide NIPSCO a reasonable opportunity to earn a reasonable return on its invested capital and recover its necessary and reasonable operating expenses.

S. Curt A. Westerhausen. Mr. Westerhausen stated that NIPSCO had three overall policy objectives in the development of the rates proposed in this proceeding: (1) restructure the industrial rate classes to accommodate the large industrial customers that want to reduce their dependence on NIPSCO generation; (2) moderate rate shock for the other rate classes; and (3) ensure that rate design calculations are simple and transparent.

Mr. Westerhausen described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 14, including the Schedule of Rates, Riders, and General Rules and Regulations and explained how the proposed tariff differs from NIPSCO's currently effective IURC Electric Service Tariff, Original Volume No. 13. He explained that the service structure would remain the same for residential and commercial customers, except for a proposed increase in fixed recovery by increasing customer charges. He noted that NIPSCO is proposing a new industrial service structure and proposing to discontinue its ECR Mechanism and Interruptible Industrial Service (Rider 775). He noted that the current rates have been updated to reflect NIPSCO's proposed revenue requirement allocated to the rate classes through the ACOSS and mitigation model.

In describing NIPSCO's new industrial service structure, he explained that NIPSCO is proposing new Rates 830 and 831 to replace current Rate 732 (Industrial Power Service), Rate 733 (High Load Factor Industrial Power Service), and Rate 734 (Industrial Power Service for Air Separation & Hydrogen Production Market Customers) utilized by NIPSCO's largest industrial customers. He stated that under proposed Rate 831, there is no longer a need for the interruptible Rider 775, which NIPSCO is proposing to eliminate. He also stated that Back-Up and Maintenance Service is available to Rate 831 customers under revised Rider 876 and Back-Up and Maintenance Service is built into the rate structure under Rate 830. He noted that Riders 881 and 882 are still available to these customers with minimal changes.

Mr. Westerhausen stated that NIPSCO's current ECR Mechanism is applicable to all Rates and is filed semi-annually to recover Environmental Compliance Projects, as authorized by the Commission. He explained that since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECR Mechanism, which will have no significant change in timing for NIPSCO or customers and relieves NIPSCO and its stakeholders of the ECR semi-annual tracker filing.

Mr. Westerhausen summarized each of NIPSCO's Proposed Rates including a discussion of each rate's components and an overview of the changes made and the rationale for making them. He testified that other than updated billing rates, Rates 820, 821, 822, 823, 824, 825, 826, 841, 842, 844, 855, 860, and 865, continue substantially unchanged. He described the material changes to the other Proposed Rates as follows:

Rate 811 – Rate for Electric Service, Residential (RS): Rate 811 is available to Residential and farm Customers. This rate consists of a Customer Charge, an Energy Charge, and applicable Riders. Other than updated billing rates, Rate 811 continues substantially unchanged.

Rate 830 – Rate for Electric Service, Industrial Power Service – Small: Rate 830 is available to Industrial Customers taking service at Transmission or Sub-transmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Sub-transmission capacity sufficient to meet the Customer's requirements. The Customer shall contract for a definite amount of electrical capacity, which shall be more than 10,000 kW and not exceed 25,000 kW. Those Premises served under Rates 732 or 733 on October 31, 2018, that satisfy the maximum capacity limitation may elect to be grandfathered into this rate.

Customers taking Back-Up, Maintenance, and Temporary Services under this rate shall be subject to Curtailments when curtailment of NIPSCO's Customers under Rate 831 is insufficient. This rate consists of a Demand Charge, an Energy Charge, and applicable Riders (except for Buy-Through Energy under Temporary or Back-Up Service). This rate is further discussed by witnesses Campbell and Kelly.

Rate 831 – Rate for Electric Service, Industrial Power Service – Large: Rate 831 is available to Industrial Customers taking service at Transmission or Sub-transmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Sub-transmission capacity sufficient to meet the Customer's requirements. Customers shall contract for a definite amount of electrical demand, which shall not be less than 10,000 kW for a five-year term. Rate 831 has three tiers of service: (1) Tier 1 – Firm Service; (2) Tier 2 – Non-Firm Market Price Service; and (3) Tier 3 – Non-Firm Third-Party Generation Service. Customers must demonstrate or document, to NIPSCO's satisfaction, the ability to reduce demand to the Tier 1 elected level plus additional firm capacity procured, as allowed, under Tier 2 and Tier 3. If a Customer's elected service results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating NIPSCO's satisfaction that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3. This rate consists of a Demand Charge (Tier 1), an Energy Charge (Tier 1), a Transmission Charge (Tier 1, Tier 2, and Tier 3), an Adjacent Affiliate Qualifying Facility Premise Transmission Charge ("AAQFPTC") (Tier 1, Tier 2, and Tier 3), and applicable Riders. This rate is further discussed by witnesses Campbell and Kelly.

Rate 850 – Rate for Electric Service, Street Lighting (SL): Rate 850 is available for street, highway and billboard lighting service to Customers for lighting systems located on NIPSCO's electric supply lines. Billing is based upon type, ownership, and responsible maintaining party of the lighting fixture. This rate is comprised of a Lamp Charge, an Energy Charge, and applicable Riders. Other than updated billing rates, Rate 850 continues substantially unchanged.

While NIPSCO is not proposing any changes to the structure of this rate, communities that are currently receiving subsidies from NIPSCO's TDSIC rates will stop receiving those subsidies once NIPSCO's new base rates are approved. NIPSCO is proposing to roll the Electric TDSIC tracker rate base as of December 31, 2019, into the revenue requirement. As such, NIPSCO is proposing that all customers served under the TDSIC program as of December 31, 2019, will move to its standard street lighting program. For those customers that have LED street lighting TDSIC replacement installations completed on or after January 1, 2020,[33] NIPSCO is not proposing any changes. That is, they would be charged under the proposed TDSIC installed LED rates.

Mr. Westerhausen summarized NIPSCO's Proposed Riders. He testified that Riders 877, 878, 879, 880, 883, 886, 887, and 888 continue substantially unchanged. [34] He described the changes to the other Proposed Riders as follows:

Rider 870 – Adjustment of Charges for Cost of Fuel Rider (FAC): Rider 870 has been updated with the average cost of fuel in base rates in this proceeding. The test year fuel costs were included in the ACOSS model and allocated by energy at the generator, as discussed by witness Gaske. Due to the elimination of Rider 775, 25% of costs associated with credits paid for interruptible and/or curtailable load under Rider 775 will no longer be passed through this Rider. NIPSCO is also proposing to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider, as discussed by witnesses Shikany and McCuen. The Fuel Cost Charge is shown in Appendix B.

Rider 871 – Adjustment of Charges for Regional Transmission Organization (RTO): Rider 871 is a semi-annual mechanism to recover net non-fuel MISO costs and revenues above and below $16,585,108 on an annual basis and 50% sharing of off-system sales margins over and under $4,741,390 on an annual basis. NIPSCO is proposing to fully track MISO non-fuel costs (net of revenues) and recover the costs through the RTO. NIPSCO is also proposing to reset the off-system sales and back-up and maintenance margin credits in base rates to zero and credit 100% of margins annually, as discussed by witness Campbell. NIPSCO is proposing to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider, as discussed by witnesses Shikany and McCuen. The production and energy allocators utilized for purposes of allocating the costs inside

[33] NIPSCO currently estimates that 19,000 LED street light installations will be completed on or after January 1, 2020.
[34] In Riders 883, 886, 887, and 888, NIPSCO is proposing to separately state the URT on customer bills instead of including it in the calculation of the factors.

of this Rider will be updated based upon the ACOSS. The RTO Adjustment Factors are shown in Appendix C.

Rider 874 – Adjustment of Charges for Resource Adequacy (RA): Rider 874 is a semi-annual mechanism to recover the cost of capacity purchases and sales and 75% of costs associated with credits paid for interruptible load. Due to the elimination of Rider 775, 75% of costs associated with credits paid for interruptible load under Rider 775 will no longer be passed through this Rider. NIPSCO is also proposing to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider. This is further discussed by NIPSCO witnesses Shikany and McCuen. The production and energy allocators utilized for purposes of allocating the costs inside of this Rider will be updated based upon the ACOSS. The RA Adjustment Factors are shown in Appendix F.

Rider 876 – Back-Up and Maintenance Industrial Service Rider (BMIS): This Rider is only available to Customers taking service under Rate 831 who desire to take service subject to Curtailments from NIPSCO for Back-Up or Maintenance purposes. Nothing in this Rider excuses the Customer from its Rate 831 Tier 2 and Tier 3 Curtailment obligations or the penalties associated with failing to meet those obligations. Back-Up and Maintenance Services under this Rider shall be subject to Curtailments when Curtailment under Rate 831 is insufficient. Energy under this Rider shall be subject to other Riders as identified on Appendix A. Customers taking service under this Rider shall operate their cogeneration facilities to meet their demand in excess of the sum of their Rate 831 Tier 1, Tier 2, and Tier 3 Contract Demands except when their cogeneration facilities are experiencing a forced outage or derate, or when the Customer is taking confirmed Maintenance Service under this Rider, as further discussed by witness Campbell. A contract is required for Back-Up Service under this Rider. The billing rates have been updated.

Rider 881 – Demand Response Resource Type 1 (DRR-1) – Energy Only (DRR 1): Rider 881 is available to Customers taking service under Rates 823, 824, 825, 826, 830, or 831 who have sustained ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 831 and registered as an LMR; unless MISO rules change and do not permit load used by NIPSCO as an LMR to also participate as a Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rate 830 or 831. The Customer shall enter into a written contract with NIPSCO to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with NIPSCO acting as the Market Participant for the Customer. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC). Changes were made to better align with proposed Rate 830 and Rate 831. NIPSCO also has removed the Marginal Forgone Retail Rate ("MFRR") provisions within the Rider to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. This is further discussed by witness Campbell.

Rider 882 – Emergency Demand Response Resource (EDR) – Energy Only (EDR-1): Rider 882 is available to Customers taking service under Rates 823, 824, 825, 826, 830, or 831 who have a sustained ability to reduce energy requirements through indirect participation in MISO wholesale energy market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 831 and registered as an LMR; unless MISO rules change and do not permit load used by NIPSCO as an LMR to also participate as an Emergency Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rate 830 or 831. The Customer shall enter into a written contract with NIPSCO to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with NIPSCO acting as the Market Participant for the Customer. Customers who do not qualify as an LMR may, however, participate as an EDR with any load. Customers taking service under this Rider shall not take power under the temporary, surplus power, back-up and maintenance services during an event under this Rider. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC). Changes were made to better align with proposed Rate 830 and Rate 831. NIPSCO also has removed the Marginal Forgone Retail Rate ("MFRR") provisions within the Rider to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. This is further discussed by witness Campbell.

Mr. Westerhausen stated the majority of changes in the Proposed Rules relate to the addition of definitions that are needed relating to the addition of Rate 831. He sponsored NIPSCO's proposed standard electric contract for service as Attachment 19-B. He noted the agreement has been revised to: (1) update the applicable rates; (2) incorporate information required under Rate 831; (3) remove information previously required under Rider 775; (4) include Rate 830 under Back-Up Service; and (5) add a notice and correspondence information.

Mr. Westerhausen sponsored a summary of billing determinants for the Historic Base Period, 2018 Budget Period and Forward Test Year as Attachment 19-C. He stated the 2019 adjusted projected billing determinants were utilized for the development of the proposed rate design in this proceeding.

Mr. Westerhausen also presented a detailed description of the three sets of customer migrations for this case: 2017 Large Customers, 2019 large Customers, and 2019 Small Customers and explained how these customers were migrated. Mr. Westerhausen described and supported the following proposed pro forma adjustments:

Adjustment Rev 1A-17 and FP 1A-17 on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to increase test year operating revenue levels by $5,966,365 to reflect a normalized level of revenue at NIPSCO's tariff rates.

Adjustment Rev 1B-17 on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $44,239,220 to normalize 2017 revenues for the TCJA.

Adjustment Rev 1D-17 and FP 1B-17 on Petitioner's Exhibit No. 4, Attachment 3-C-S2, REV 1. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $352,249 for large customer rate migration in order to match migrations included in the budget for the 12 months ending December 31, 2018 and 2019.

Adjustment Rev 1A-19R and FP 1A-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $933,450 to normalize weather by converting the budget weather normal definition for CDD and HDD of 35-years ended 2010 to the regulatory 30-years ended 2017 definition for CDD and HDD, which is consistent with past ratemaking practice.

Adjustment Rev 1C-19R and FP 1C-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $45,845,611 to update the pricing model utilized in the budget process. When NIPSCO modeled the anticipated change in industrial customer usage described in Adjustments Rev 1D-19R and Rev 1A-19SS, NIPSCO updated the PROMOD inputs utilized to determine the volumes generated at each station. This resulted in changes in revenues, fuel costs, fuel handling expense, variable chemicals, and coal inventory. If this adjustment is not included, Forward Test Year electric operating revenues would be overstated. A corresponding adjustment was to decrease Forward Test Year fuel and purchased power expense in the amount of $45,845,611 in Adjustment FP 1C-19R.

Adjustment Rev 1D-19R and FP 1D-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1 and FP 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $76,792,660 related to the migration and annualization of large industrial customers. If this adjustment is not included, Forward Test Year electric operating revenues would be overstated. A related adjustment was made to decrease Forward Test Year fuel and purchased power expense in the amount of $31,507,991 in Adjustment FP 1D-19R.

Adjustment Rev 1F-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to increase Forward Test Year electric operating revenues in the amount of $4,507,281 to reflect the discount passed through to retail electric customers taking service under NIPSCO's EDR.

Adjustment Rev 1G-19R and FP 1F-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $1,488,190 to reflect an anticipated decrease in street lighting billing determinants because the budget did not anticipate the increase in customer participation under the LED street lights resulting in less usage.

Adjustment Rev 1A-19SS and FP 1A-19SS on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $83,630,802 to reflect changes in

industrial fuel based on the proposed new service structure.

Adjustment Rev 1B-19SS on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 1. NIPSCO proposes to decrease Forward Test Year electric operating revenues in the amount of $3,000,000 to remove all Rate 732 and 733 back-up and maintenance revenues based on the proposed new service structure that gives Rate 831 customers alternatives for Back-Up and Maintenance Services. Any Back-Up and Maintenance margins generated by Rider 876 and within Rate 830 will be passed back in the RTO tracker.

Adjustment Rev 7-19R on Petitioner's Exhibit No. 4, Attachment 4-C-S2, REV 7. NIPSCO proposes to decrease Historic Base Period electric operating revenues in the amount of $10,822,388 for DSM lost revenues that will continue to be recovered through NIPSCO's DSM tracker filing after Step 1 base rates are implemented.

Mr. Westerhausen explained the proposed increase in the Trip Charge. NIPSCO is proposing to increase the revenue collected in the Forward Test Year by $18,780. If a Customer schedules an appointment in association with a service request, and NIPSCO's serviceman is not able to gain access to the Customer's facilities due to the absence of the Customer, the Customer shall be charged a Trip Charge when the appointment is rescheduled by the Customer. NIPSCO is proposing a $15 increase in this charge, raising it from $40 to $55. In the Historic Base Period, there were 1,252 trips made. Applying this same number of trips to the Forward Test Year, multiplied by the $15 increase in the Trip Charge results in an $18,780 increase.

Mr. Westerhausen explained the proposed increase in the Reconnection Charge. NIPSCO is proposing to increase the revenue collected in the Forward Test Year by $164,280. A Customer incurs a Reconnection Charge whenever the service has been turned off by NIPSCO in accordance with Rule 12 (shut off for non-payment). NIPSCO is proposing a $20 increase in the charge for normal working hours, raising it from $70 to $90. In the Historic Base Period, 8,214 disconnect/reconnect trips were made. Applying this same number of trips to the Forward Test Year, multiplied by the $20 increase in the Reconnection Charge results in a $164,280 increase.

Mr. Westerhausen described how the Rate 830 Billing Determinants were derived. Customers taking service on the proposed Rate 830 are coming from both Rates 732 and 733. The starting point for the Rate 830 demands, energy and reactive kV Amps is the 2019 forecast. Proposed Rate 830 has different contract requirements than the current Rates 732 and 733. The 2019 demand forecast is based on the current rates and ratchets. NIPSCO reviewed the 12 months ending September 2018 demand billing components and recalculated these billing demands based on the customer's on-peak and off-peak demands and eliminated any influents of current contract demands. The forecasted billing demands were reduced to these recalculated billing demands.

Mr. Westerhausen described how the Rate 831 Billing Determinants were derived. He explained that customers taking service on the proposed Rate 831 are coming from Rates 732, 733, and 734. The starting point for the Rate 831 demands, energy, and reactive kV Amps is the 2019 forecast. Proposed Rate 831 has three tiers of service and allows customers with multiple premises to aggregate their load on an hourly basis. The customers can select a Tier 1 contract demand, which when multiplied by 12 becomes their annual billing demand. NIPSCO took the customers

2017 actual hourly demands, aggregated them for the two customers where aggregation applies, and then calculated the hourly Tier 1 and Tiers 2 and 3 energy. These were them summed to calculate the customer's annual 2017 energy for Tier 1 and Tiers 2 and 3. The 2017 energy was compared to the 2019 forecast energy. For customers with a Tier 1 energy with a 99% or higher load factor, Tier 2 and 3 energy was adjusted. For Customers with a Tier 1 load factor below 99%, the adjustment was made at the same proportion as their 2017 Tier 1, Tier 2, and Tier 3 energy. Transmission flow studies were performed for two customers who have multiple Premises held under common ownership or by affiliates (as defined in Ind. Code § 23-1-43-1) and having the same qualifying service voltage, IDR meters with five-minute interval telemetry capability at those Premises. Transmission volumes were calculated for the gross energy consumption (not netted with potential outputs from other qualifying meters) of each individual IDR meter. Their Tier 2 and 3 energy was adjusted based on these studies. No adjustments were made to the forecasted reactive kV Amps.

Mr. Westerhausen described NIPSCO's proposed updates to the tracker allocators. He explained that Rate 831 contains three tiers of service with the current trackers applicable to Tier 1 firm service. The energy only revenue requirement of the RTO would also apply to Tier 2. Currently, it is assumed that no transmission-related costs will remain in the FMCA, but if that changes in the future, transmission-related charges would apply to both Tier 2 and Tier 3 transmission portion of Rate 831. The demand allocators are based on the mitigated allocation of the ACOSS revenue. The Rate 831 allocation was adjusted to reduce the ACOSS revenue down to the revenue associated with Tier 1. The energy allocators are based on the sales allocator from the ACOSS. The Rate 831 sales are strictly Tier 1 sales so no adjustment is required. He explained that Rate 831 Tier 2 transmission volumes are not known at this time, so a placeholder has been included in the allocation. The TDSIC transmission allocators are based on the transmission and sub-transmission allocation of the revenues in the ACOSS. Rate 831 has been adjusted to the transmission volumes for Tier 1. The TDSIC distribution allocators are derived from the primary and secondary distribution revenue from the ACOSS. No adjustments were made for Rate 831. The tracker allocations are provided in Attachment 19-F.

7. OUCC Case-in-Chief.

A. Michael D. Eckert. Mr. Eckert recommended that NIPSCO's Phase 1 revenues should be decreased by $30,630,526 or 2.14% based on a WACC of 6.25%, and NIPSCO's Phase 2 revenues should be decreased by $10,233,307 or 0.71% based on a WACC of 6.27%. He reviewed NIPSCO's test-year operating expenses and related pro forma operating expense adjustments and accepted several of NIPSCO's adjustments, modified a few of NIPSCO's adjustments and proposed additional adjustments. He also sponsored the following adjustments: Billing Determinants – Revenues, Billing Determinants – Fuel Production, Labor Adjustment, Corporate Incentive Plan Expense, Pension Expense, OPEB Expense, medical Benefits Expense, Other Benefits Expense, Other Employee Benefits, Long-Term Incentive Compensation and Profit Sharing ("LTIP") Expense, Benefits Administration Expense, Uncollectible Expense, Vegetation Management Expense, Bad Debts Expense, and Interest Synchronization.

Mr. Eckert stated Mr. Novak's billing determinant adjustment increases the amount of kWh sales for NIPSCO, which in turn increases the total fuel production expense. He calculated the increase to fuel production expense by subtracting NIPSCO's proposed billing kWh billing

determinants from the OUCC's proposed kWh billing determinants and multiplying it by NIPSCO's proposed fuel cost rate resulting in a $1,686,881 increase in fuel production expense.

Mr. Eckert stated Mr. Blakley made recommendations and proposed changes to NIPSCO's ADIT, which he incorporated into the OUCC's revenue requirement calculation.

Mr. Eckert calculated total labor expense as $130,478,191 using NIPSCO's method for calculating labor expense in making his calculation; however he used the actual average headcount for calendar year 2018, which is the same actual average headcount for calendar year 2017, rather than NIPSCO's budgeted headcount for calendar year 2019, resulting in a reduction in labor expense of $6,707,894. He also changed Corporate Incentive Plan, Pension Expense, OPEB, Medical Benefits, Other Benefits, Other Employee Benefits, Long Term Incentive Plan, Benefits Administration Expense, and payroll tax to reflect the reduction to labor expense. Mr. Eckert calculated these adjustments by taking the projected amounts for each of these expenses as reflected in NIPSCO's pro forma number and reduced them by the 4.89% reduction in labor expense, resulting in a combined total downward adjustment of $2,459,206.

Mr. Eckert did not oppose NIPSCO's adjustment to rate case expense, but he recommended NIPSCO reduce base rates for the amortization of rate case expense once the amortization period expires. He supported the continuation of the purchased power over the benchmark calculation.

Mr. Eckert did not oppose NIPSCO's proposal to defer unrecovered ECR expenses and amortize them over two years; however the OUCC recommended that NIPSCO reduce base rates for the amortization of expenses once those amortization periods have expired.

Mr. Eckert did not oppose NIPSCO's proposal that the FAC Rider be modified to reflect the updated cost of fuel that will be established in this base rate case. The OUCC recommended the Commission allow the continuation of the agreement with NIPSCO that allows the OUCC and intervenors to file their testimony and report 35 days after NIPSCO files its petition and testimony.

Mr. Eckert had no concerns with NIPSCO's proposed changes to its RTO Tracker. He stated that since NIPSCO will not know what customers will partake in NIPSCO's requested Rate 831, Tier 2 and 3, until the time of Phase 2 rates, or until and if approved by the Commission, the OUCC does not oppose NIPSCO's proposal to not embed an amount for MISO non-fuel costs and revenues in base rates; however, if Rate 831 is denied by the Commission, and similar to other Indiana investor-owned utilities, there may be a reason to embed an amount of MISO non-fuel costs and revenues in base rates, as there may not be any unknowns and embedding an amount in base rates may reduce the volatility of costs through the rider. The OUCC also did not oppose NIPSCO's proposal to reset OSS margin credit in base rates to zero dollars and track 100% of all OSS margins above zero dollars as a credit to customers through the RTO Rider. The OUCC also did not have any concerns with NIPSCO's proposal to pass back 100% of any demand margins resulting from back-up and maintenance services as a credit to customers through the RTO Rider.

Mr. Eckert testified the OUCC does not oppose NIPSCO's proposal to remove the interruptible credit from the RA Tracker. The OUCC also does not oppose NIPSCO's proposal to remove all embedded costs and/or credits associated with capacity from base rates and track 100% of all capacity costs and/or credits as a charge/credit to customers through the RA Tracker because

such treatment of capacity purchase costs and sales credits: as (1) NIPSCO relies on the MISO PRA to sell excess capacity; (2) NIPSCO does not control the MISO PRA clearing prices associated with capacity; and (3) the auction process can vary.

With regard to the cost allocation factors for NIPSCO's TDSIC, Mr. Eckert recommended that the Commission require that NIPSCO use the customer class revenue allocation factors recommended by Mr. Watkins.

Mr. Eckert testified that the OUCC does not oppose NIPSCO's proposal to treat Indiana URT as a separate line item on customer bills, resulting in removal of URT from all of its riders.

B. Neha Medhekar. Ms. Medhekar testified that NIPSCO's filing includes ratepayer benefits resulting from the TCJA because the TCJA resulted in a federal tax decrease from 35% to 21%, resulting in excess deferred taxes that are being returned to the customer over the remaining life of the assets.

Ms. Medhekar stated NIPSCO's forecasted property tax expenses for 2018 and 2019 are reasonable noting that NIPSCO made an adjustment to remove MVP property taxes. She recommended NIPSCO's proposed payroll tax expense amount should be reduced based on Mr. Eckert's adjustment to O&M labor expense. She testified NIPSCO's calculation of public utility fee is consistent with the Commission's 2018 Annual Report providing the 2018-2019 public utility fee billing rate as 0.001202040.

Ms. Medhekar testified NIPSCO's customers will benefit from removing URT from basic rates, and the OUCC does not object to NIPSCO's proposal. She noted that if not approved, URT would need to be included in total cost related to taxes other than income resulting in an increase in gross retail electric revenue of $32,994,983.

Ms. Medhekar did not oppose NIPSCO's calculated state income tax rate. She explained that any adjustment to income results in an adjustment to income tax expense. As a result of the OUCC's proposed adjustment to NIPSCO's revenue requirement, there is a reduction of $573,729 for state income tax expense and a reduction of $2,021,439 for federal income tax expenses.

Mr. Medhekar has no objection to NIPSCO's calculation of state excess deferred taxes.

C. Wes R. Blakley. Mr. Blakley clarified the actual total company percentage increase in revenue requirement NIPSCO is requesting is 7.77% to arrive at its total company pro forma proposed revenues. He noted that at 1,000 kWh, if NIPSCO's requested increase were approved in its entirety, a typical residential customers would experience an 11.54% rate increase or $15.11 per month increase.

Mr. Blakley calculated NIPSCO's annual accrual depreciation using the 2019 forecasted future accruals in the depreciation study, and applied the results to the composite remaining life of the coal assets from its depreciation study in Cause No. 44688, resulting in an increase to NIPSCO's annual depreciation accruals of approximately $42 million. He stated the accelerated depreciation proposed by NIPSCO provides additional annual cash flow of approximately $42 million that will last through 2030, which is a benefit to NIPSCO, as is the special ratemaking treatment proposed for Schahfer and the ongoing "return on" it seeks to earn on these retired coal

assets. He indicated that any increased rates due to the accelerated retirements should be mitigated. Mr. Blakley proposed a mitigation mechanism in which ratepayers are credited with the effect of the annual depreciation of Schahfer and Michigan City. He explained the credit mechanism would function similarly to a Construction Work in Progress ("CWIP")/Plant Investment tracker, in which plant investment is reduced by associated depreciation over a period, and the return "on" is calculated on the new, lower net plant balance. He explained that while the plant investment is decreasing each year due to depreciation of the investment, NIPSCO would still receive a return "on" the investment with the credit reflecting the difference between the amount authorized in rates and the actual investment amount adjusted for depreciation. He noted that the credit would be repeated annually until the physical asset or regulatory asset is fully depreciated or amortized.

Mr. Blakley disagreed with NIPSCO's proposal to return unprotected excess ADIT over the same period as the protected excess ADIT. He stated that the public interest would not be served by allowing NIPSCO to amortize unprotected excess ADIT over 26 years. He instead proposed NIPSCO amortize unprotected excess ADIT over the expected life of the rates set in this Cause for five years, resulting in an annual amortization of $36,680,662 for unprotected excess ADIT.

D. J. Randall Woolridge. Dr. Woolridge recommended a 9.25% return on common equity, an overall rate of return of 7.41% from investor-supplied capital, and a 6.27% overall fair rate of return from capital. He primarily disagreed with Mr. Rea in measuring NIPSCO's rate of return or cost of capital as follows: (1) significantly different views regarding the state of the markets and the outlook for capital costs; (2) Mr. Rea's DCF equity cost rate estimates are excess because he has (a) asymmetrically eliminated low-end DCF results, (b) relied excessively on the earnings per share growth rates of Wall Street analysists and *Value Line*, made an inappropriate adjustment for leverage, (c) made an inappropriate adjustment for flotation costs, and (d) included the DCF results of a non-utility group of companies; (3) Mr. Rea's CAPM equity cost rates are overstated because he has (a) used economists' forecasts of future interest rates, (b) made a market value – book value leverage adjustment to his betas, (c) employed inflated historical and projected MRPs that do not reflect current market fundaments, (d) included unjustified size and flotation cost adjustments, (e) used the CAPM results of a non-utility group of companies, and (f) employed a variance of the CAPM; (4) Mr. Rea's risk premium approach produces inflated equity cost rates for NIPSCO because he has (a) used economists' forecasts of future interest rates, (b) employed inflated historical and projected risk premiums that do not reflect current market fundamentals, (c) made a market value – book value leverage adjustment to his betas, (d) included an unjustified flotation cost adjustment, and (e) included the risk premium results of a non-regulated group of companies; and (5) Mr. Rea used a non-traditional equity cost rate approach.

E. William H. Novak. Mr. Novak stated the primary differences between NIPSCO's and the OUCC's calculations of forecasted period billing determinants are due to different forecasts for normal weather and customer growth and recommended the appropriate: (1) number of customer bills to set rates upon should be 6,761,663, an increase of 212,483; (2) billing demand should be 14,160,249, a decrease of 20,012; and (3) kWh usage should be 12,101,489,114, an increase of 65,507,561. He explained how his test period billing determinants were adjusted for weather and added customers and explained his analysis for consideration of usage for NIPSCO's industrial customers stating that he adopted NIPSCO's proposed billing determinants and revenues associated with Rates 830 and 831. Mr. Novak stated that he adopted NIPSCO's proposed test

period values for the remaining billing determinants primarily consisting of certain minimum bills related to three-phase charges, horsepower charges, and charges based on residential or commercial pumps as well as the test-period billing determinants for reconnection charges, turn-on charges, returned check charges, and automatic meter opt-out charges, which have remained relatively consistent since 2012. He stated the forward-looking billing determinants were multiplied by the current base tariff rates giving $1,412,394,583 in revenues.

F. Peter M. Boerger. Dr. Boerger testified regarding NIPSCO's proposal for a new rate design (i.e., Rate 831) that would allow certain large industrial customers to pay MISO wholesale market prices for service under Tiers 2 and 3 (non-firm) service under NIPSCO's proposed Rate 831. He indicated that the OUCC expects that access to the wholesale market will allow these customers to lower their cost of electric service compared to NIPSCO's current rates. He highlighted the significance of this issue for regulatory policy across all Indiana electric utilities in that it is a first-of-its-kind request.

Dr. Boerger presented NIPSCO's estimate, obtained through discovery, of a $40.2 million cost shift from industrial customers to other rate classes through the implementation of Rate 831. He referred to OUCC witness Watkins' testimony that this $40.2 million cost shift serves as a minimum value for the cost shift and that the shift may be higher. He explained that this cost shift would allow this class of customers to avoid a significant share of NIPSCO's legacy costs that would otherwise be allocated to these customers under a cost-based rate. He presented the OUCC position that because of this cost shift, NIPSCO's proposal is not reasonable without a payment from Rate 831 customers, which he called a "transition charge" to be recovered over the period through which NIPSCO recovers accelerated depreciation on its coal-fired plants. Under this OUCC proposal, the exact size of the annual transition charge would be determined in the Phase 2 rate proceeding in this Cause, which would also be used to adjudicate the effects of Rate 831 customers not subscribing to the amount of firm service that NIPSCO envisioned in designing Rate 831 charges. The revenues from the transition charge would be allocated to other rate classes based upon the production cost allocation methodology approved in this Cause.

Dr. Boerger also presented concerns about Rate 831 tariff provisions. Specifically, he identified the early termination of Rate 831 contract provisions under Section 5.8 of its proposed tariff, which otherwise requires a five-year contract provision before customer commitments to firm service can be reduced and a five-year notice provision before a customer's firm service can be increased. He stated that these notice provisions are important to the reasonableness of the tariff and should not be allowed to end prematurely. In response to that concern, he presented the OUCC recommendation that Section 5.8 provisions not apply to Rate 831 contracts. Another Rate 831 provision with which Dr. Boerger takes issue pertains to the allowed 12-month notice provision for reducing firm service in the event of "aggregation" or "partially closing a Premise." He finds these provisions to be vague and not reasonably justified and that their inclusion in the Rate 831 tariff provisions is unreasonable.

Dr. Boerger took issue with the design of NIPSCO's proposed transmission charge under Rate 831 and the related Rider 876. He stated that this transmission charge was intended by NIPSCO to recover the Rate 831 share of transmission revenue requirement, and identified that the OUCC does not object to the inclusion of a transmission charge in NIPSCO's tariff. However, he explained that the proposed charge would not adequately recover the cost of providing service

for back-up of self-generation facilities, in that it only charges those facilities for the service of wheeling electricity at the time of unexpected generation outages to the exclusion of the cost of providing service for "standing ready" to move power, which is a 365 day per year service. He explained that the charge as proposed by NIPSCO would under-recover revenue requirement for the back-up transmission service and provide inappropriate economic signals for the building of self-generation facilities. He recommended that NIPSCO's transmission charge be designed to recover transmission revenue requirement on the basis of demand, including the amount of demand needed to back-up self-generation facilities. This approach would require establishing a contract level of back-up service for self-generation facilities, which would be reflected in the potential peak load from Rate 831 customers' non-firm transmission needs. He further recommended that NIPSCO rerun its cost of service and rate design analysis to include such non-firm demand, including back-up of self-generation, which should be presented in the Phase 2 rate proceeding in this Cause. Finally, he recommended that such a transmission charge be included as part of any successor to NIPSCO's 700 series of rates if NIPSCO's Rate 831 proposal is not approved.

G. Glenn A. Watkins. Mr. Watkins testified regarding Cost of Service, which addresses the reasonable allocation of NIPSCO's revenue requirement to the various customer classes. He testified that NIPSCO filed this case in part due to its proposed rate restructuring plan for large industrial customers that would allow these customers to purchase the majority of their energy requirements in the wholesale market and would collectively save on average approximately $47.1 million annually on their total electric bills based on their 2017 and 2018 actual usages and load profiles. As a result of NIPSCO's proposed industrial ratemaking plan, all remaining customers would be responsible for NIPSCO's total investment in generation plant. He stated that even though NIPSCO's generation plant was planned and built in large part to meet the load and energy requirements of large industrial customers, these large customers would be able to walk away from any cost responsibility associated with NIPSCO's legacy fixed generation costs wherein all remaining customers would be responsible for the entire cost of NIPSCO's generation plant. Mr. Watkins estimated the impact on all other customers' rates and revenues of NIPSCO's proposed industrial rate restructuring plan is in the range of $40.2 million to $80.2 million.

Mr. Watkins discussed NIPSCO's rate restructuring plan and how the largest industrial customers would qualify for Rate 831 in which these customers will contract for a specified amount of firm capacity during each hour of the year and any additional load would be purchased at the prevailing day ahead wholesale LMP. NIPSCO projected only a small portion of these large industrial customers' loads will be provided from NIPSCO's own generation resources. The vast majority of these large industrial customers' loads and energy requirements will bypass NIPSCO's generation resources wherein these load and energy requirements will be purchased directly from the wholesale market. Mr. Watkins testified that under NIPSCO's proposed restructuring plan, the majority of large industrial loads will bypass NIPSCO's generation system such that the remaining residential, commercial, municipal, and small industrial customers must then pick up a much larger percentage of NIPSCO's fixed, or sunk, generation plant-related costs. As a result of these large industrials bypassing NIPSCO's generation system, a significant portion of NIPSCO's fixed generation costs would be stranded absent an alternative ratemaking plan. He discussed how he has not been able to quantify the impact on all other customers with any level of precision because NIPSCO has presented its case as if the plan will be accepted by the Commission. He stated that NIPSCO has not presented its evidence based on the actual current rate structure but rather, only after all of the numerous large industrial adjustments are made as proposed under its rate

restructuring plan. Through discovery, Mr. Watkins was able to determine a range for the impact on all other customers in the range of $40.2 million to $80.2 million.

To support his position that Rate 831 would reduce large industrial customers' total electric bills, Mr. Watkins used 2017 and 2018 data from multiple data request responses (total electric bills, total kWh consumption, hourly loads, and hourly MISO day-ahead LMPs), along with each customer's projected contract demands from Dr. Gaske's Attachment 18-H. Mr. Watkins then compared each customer's proposed Rate 831 total electric bill with actual total bills for 2017 and 2018. He concluded Rate 831 customers would have saved $69.5 million during 2017 and $24.8 million during 2018 for a two-year average annual savings of $47.1 million.

Mr. Watkins addressed the allocation of generation and transmission costs to the customer classes. With regard to generation plant, Mr. Watkins testified that utilities design and build generation facilities to meet both the energy (kWh) requirements and the demand (kW) requirements of their customers on a collective basis. He explained because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated. Mr. Watkins discussed how utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity kW and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year, there is an optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Mr. Watkins explained that methods focused solely on seasonal peaks, such as 1CP and 4CP, are inconsistent with the way utilities plan their systems to meet both peak requirements and their customers' energy requirements throughout the year. He stated that NIPSCO's portfolio of generating assets is comprised predominately of large baseload units that serve the energy needs of NIPSCO throughout the entire year. Furthermore, the total dollar amount of generation investment for utilities such as NIPSCO that have coal generation facilities includes a majority of its net investment to comply with environmental or pollution control requirements. These environmental or pollution control investments are related to the burning of fuel, which is energy-related. As a result of the energy/capacity cost trade-off and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes. Mr. Watkins demonstrated that a majority of NIPSCO's generation investment is related to baseload units that serve all customers throughout the year, which the Commission has previously recognized. Mr. Watkins cited to NIPSCO's last litigated rate case (Cause No. 43526), where the Commission found (at p. 85):

> Much of the capital investment costs at issue were, in fact, incurred to meet NIPSCO's energy requirements at lower costs thereby minimizing the total cost of service. This is consistent with the evidence that NIPSCO's system was designed, planned, and built in material part to serve the loads of its energy intensive

industrial customers. Moreover, we note that the most recent capacity addition to the NIPSCO system was the intermediate/baseload combined cycle Sugar Creek facility, and not a "peaker" generating plant.

Mr. Watkins discussed how Dr. Gaske conducted his COSS utilizing the 4CP method to allocate generation costs. Under Dr. Gaske's 4CP method, the entire amount of NIPSCO's generation plant investment is allocated based on four hours of peak demand. Dr. Gaske assumed that the cost per kW is the same for baseload units as for peaker units, and he has also assumed that the utilization of NIPSCO's baseload units are the same as its peaker units; i.e., peaker units are dispatched and run at the same level throughout the year as baseload units. Mr. Watkins testified that Dr. Gaske indicated either the 4CP or 12CP methodology would be appropriate for NIPSCO's production function, but he chose to only use the 4CP allocation method for NIPSCO's fixed production costs in this case. Mr. Watkins testified that the Commission has previously approved the 12CP methodology for NIPSCO and in fact, directed NIPSCO to utilize a 12CP study as the initial basis on which to determine class revenue responsibilities (43526 Final Order, p. 85). Mr. Watkins testified that Dr. Gaske's 4CP COSS results in several classes receiving a free ride and assign no generation cost. Even though these customers require generation service, they are not assigned a single dollar of rate base associated with generation capacity costs.

Mr. Watkins explained that neither NIPSCO nor Dr. Gaske conducted a cost allocation study based on the current configuration of customer classes, the current usage and load profiles of its various customer classes, nor the current revenues associated with NIPSCO's retail customers. Rather, NIPSCO and Dr. Gaske have presented their case under the assumption that the Commission will approve NIPSCO's proposed Rates 830 and 831 restructuring. As such, Dr. Gaske's COSS only reflects NIPSCO's proposal that a significant amount of large industrial load will leave the NIPSCO system for generation purposes. He stated that this has a profound impact on COSS results. Under NIPSCO's proposals and Dr. Gaske's COSS analysis, all other customers are then allocated the full amount of NIPSCO's capacity-related generation costs wherein the large industrial classes' loads are expressed at significantly reduced levels due to Rates 830 and 831. Mr. Watkins explained this choice by NIPSCO as problematic, and due to the massive number of adjustments that are interrelated to NIPSCO's proposed rate restructuring for Rates 830 and 831, he was not able to create or depict NIPSCO's total costs and revenues under the actual current rate configuration and customer profiles. Additionally, Dr. Gaske only utilized the results of his COSS to assign revenue responsibility to, and design rates for, the proposed Rate 831 rate schedule. With regard to all other rate classes, Dr. Gaske assigned any remaining overall increase in the revenue requirement to classes on an equal percentage basis.

Mr. Watkins explained that to show the relative shift in cost responsibility as a result of NIPSCO's proposal to present its case based on the assumption that its Rate 831 restructuring proposal will be accepted, he had to use Dr. Gaske's 4CP COSS from NIPSCO's last rate case. Mr. Watkins then compared Dr. Gaske's 4CP allocators in that case to his 4CP allocators in this case to show the relative shifts in generation costs. NIPSCO's proposed large industrial rate restructuring plan greatly reduces the large industrials' allocation of generation-related costs from 29.80% in the last case to 11.88% in this case. Mr. Watkins explained that Dr. Gaske must then allocate more costs to the remaining classes. For example, the residential class' generation allocation factor increases from 30.28% to 42.07%.

Mr. Watkins conducted three alternative COSS using the Base-Intermediate-Peak ("BIP"), Peak and Average ("P&A"), and 12CP allocation methodologies. He stated that based on NIPCSO's configuration of generation resources and its load profile, the BIP and P&A methods better reflect the capacity/energy tradeoffs that exist within NIPSCO's generation-related costs. Additionally based on the Commission's prior acceptance of the 12CP method to allocate NIPSCO's generation-related costs, he conducted COSS using each of these three allocation methodologies. Mr. Watkins discussed how BIP and P&A methods more closely reflect the manner in which NIPSCO has planned, built, and utilizes its generation resources and more closely correlates to cost causation; however, the 12CP method is not an unreasonable approach that this Commission has used for allocating NIPSCO's generation costs for several rate cases. Mr. Watkins demonstrated the proposed Rate 831 revenue requirement (using NIPSCO's requested increase) under the alternative allocation methods is: (1) 4CP: $149,068,200; (2) BIP: $172,911,300; (3) P&A: $169,096,200; and (4) 12CP: $162,158,600. He concluded that the difference between Rate 831 revenue requirement from Dr. Gaske's 4CP to the more reasonable Commission-approved 12CP methodology allocates $13,090,400 more to large industrial customers.

Mr. Watkins testified that NIPSCO's proposed class revenue distribution is reasonable with one major caveat. He stated that if the Commission adopts NIPSCO's Rate 831 proposal for large industrial customers, NIPSCO's proposal to develop Rate 831 rates based only on his allocated revenue requirement for this class is unfair and unreasonable to all other customer classes. He stated that this is because Dr. Gaske's allocated revenue requirement for Rate 831 is based upon these customers bypassing NIPSCO's generation system for the majority of their load and energy requirements. Under NIPSCO's proposal, all other customers would be responsible for the level of fixed generation investment that large industrial customers would walk away from. To help alleviate this cost shift, he recommended if the Commission authorizes some form of Rate 831, it should use a more appropriate cost allocation method and implement a transition charge.

Mr. Watkins testified that due to the manner in which NIPSCO presented its case, cost responsibility across classes cannot be determined. Based on this, Mr. Watkins agreed the most reasonable method to assign the remaining increase is across classes on an equal percentage basis.

Mr. Watkins discussed how NIPSCO has requested to increase fixed customer charges for residential and small commercial rate classes even though these customer charges were recently increased by a significant percentage in Cause No. 44688. Mr. Watkins conducted a residential direct customer analyses, which showed at most residential direct customer cost is $5.31 per month, and a small commercial direct customer cost is at most $9.15 per month. Mr. Watkins recommended that even though his direct customer cost analyses indicates that significant reductions to current fixed monthly customer charges applicable to residential and small commercial customers are appropriate, in the interest of rate continuity, gradualism, and impacts on individual customer bills that the current monthly customer charge of $14.00 for residential and $24.00 for small commercial (Rates 720, 721, and 722) be maintained.

8. CAC Case-in-Chief.

A. Jonathan Wallach. Mr. Wallach addressed NIPSCO's proposals to: (1) restructure service for large industrial customers; (2) allocate among the various rate classes the

forecasted revenue deficiency for the 2019 test year; and (3) increase the monthly customer charge for residential customers based on the results of NIPSCO's ACOSS.

Mr. Wallach provided an overview of NIPSCO's proposal for a new industrial service structure, described how NIPSCO determined the amount of demand-related embedded production costs to be recovered through the proposed Tier 1 demand charge, and explained how test-year demand-related production costs would be allocated to large industrial customers if industrial service is not restructured. Mr. Wallach stated that NIPSCO has always faced the risk of loss of industrial load – with the associated loss of contribution to NIPSCO's fixed costs – and has attempted to mitigate such risk with special contracts and interruptible rates. However, NIPSCO believes there is now a heightened risk due to changing economic landscape that has reduced the cost to industrial customers of alternatives to NIPSCO firm service. He stated that the proposed restructuring will result in a near-term shifting of some firm costs currently being recovered from the industrial customers to other customers.

Mr. Wallach testified that NIPSCO's Rate 831 proposal would unduly subsidize large industrial customers by shifting recovery of $67-$80 million of embedded production costs to other rate classes by allowing large industrial customers to take fixed rate service at contract demand levels well below total customer demand. He stated NIPSCO proposes to allocate embedded production costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand not contract demand. Consequently, he maintains that the proposed industrial rate structure would recover from large industrial customers less than their fair share of embedded production costs and instead shift recovery of such costs to other rate classes.

Mr. Wallach recommended that Rate 831 revenues be maintained at test-year levels under current rates and that revenues for all other classes be increased by an equal percentage to recover the requested revenue increase. He stated this would thereby reduce the industrial subsidy and provide a fair allocation of the requested revenue increase.

Mr. Wallach provided an overview of NIPSCO's proposal to increase the monthly fixed customer charge for residential customers from $14 to $17 and disagreed with NIPSCO's argument that demand-related costs are fixed for rate-design purposes. He stated that while such costs may appear fixed from a short-run accounting perspective since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load, from the long-run perspective of cost-causation and price efficiency, plant investments are variable with respect to customer usage. He stated that shifting recovery of load-related costs from the volumetric energy rate to the fixed customer charge would drive the energy rate from long-run to short-run marginal costs and thereby dampen price signals for efficient customer behavior.

Mr. Wallach recommended that the Commission approve a residential fixed customer charge at a cost-based rate of $12.55 per residential customer per month.

B. John Howat. Mr. Howat described the need for and recommended that the Commission direct NIPSCO to implement a comprehensive low-income bill payment assistance program that targets current bill benefits to customers eligible to participate in the federal Low-Income Home Energy Assistance Program ("LIHEAP") with an arrearage management design

component. According to Mr. Howat, the estimated cost of the recommended program represents just over $9 million per year—or 0.547% of NIPSCO's revenues from sales to residential, commercial, and industrial customers, which could be collected through a uniform volumetric charge. He also recommended that NIPSCO report data monthly to the Commission and stakeholders regarding general residential and low-income customer accounts, billing, receipts, arrearages, notices of disconnections, bill payment agreements, disconnections of service for nonpayment, reconnections of service after disconnection for non-payment, accounts written off as uncollectible, and accounts sent to collection agencies. Mr. Howat presented evidence to demonstrate that shifting utility cost recovery from the volumetric to fixed monthly customer charge portion of bills disproportionately harms low-volume consumers within a rate class and recommended the Commission reject NIPSCO's proposal to increase the monthly fixed customer charge and instead, lower it to CAC's recommended figure of $12.55.

9. ICC Case-in-Chief.

A. Emily S. Medine. Ms. Medine testified that NIPSCO's proposal to allow its largest industrial customers to opt into retail wheeling and reduce or eliminate paying for generation assets built to serve their firm and interruptible loads should be rejected for the following reasons: (1) it will have significant adverse impacts on NIPSCO's other customers; (2) the proposal was not modeled in NIPSCO's 2018 IRP; (3) NIPSCO has invested heavily in generation assets to serve the firm and interruptible loads of those large industrial customers and to the extent those customers are allocated less of the cost of those assets, NIPSCO will seek to recover those stranded costs from other customers; and (4) NIPSCO's proposal for retail wheeling for large industrials customers raises statewide policy issues that are inappropriate for resolution in a rate case. She recommended that NIPSCO's request to allow its largest industrial customers to opt for retail wheeling should be denied without prejudice so that: (1) NIPSCO can perform truly integrated resource planning in its next IRP and include the migration of large industrial firm and interruptible load to retail wheeling; (2) the Commission can include in its Statewide Analysis and annual reporting to the legislature the issues surrounding potential migration of load to market resources in lieu of local utility resources; (3) the issue of stranded cost allocation can be considered from a policy perspective on a statewide basis.

Ms. Medine concluded that NIPSCO's proposed acceleration of depreciation for coal generation units and proposed accounting authority to defer remaining net book value of coal generation assets as regulatory assets after early retirement should be rejected for the following reasons: (1) these proposals are premature because they rely upon an IRP that is still under review and comment; (2) NIPSCO's 2018 IRP modeling suffers from the same fatal flaw as its 2016 modeling – NIPSCO's resource planning is not integrated because it separates (a) the modeling of retirement decisions (using hardwired retirement dates selected by NIPSCO rather than optimized by the model), from (b) replacement portfolio decisions; (3) NIPSCO did not adequately address customer rate impacts that will result from the premature retirements of its remaining coal fleet, accelerated depreciation of the remaining costs and the creation of a regulatory asset; and (4) NIPSCO expended no effort in seeking to minimize the costs of the early retirement of the Schahfer units, including but not limited to, actively marketing the units for sale to third parties. She recommended that in connection with doing a truly integrated resource plan in its next IRP, NIPSCO should, as part of its retirement planning, solicit and meaningfully consider offers from third parties to purchase those assets in order to properly assess the costs of retirement. NIPSCO

should not reject without due economic analysis purchase offers that may include proposals for NIPSCO to purchase capacity or energy from those units.

Ms. Medine concluded that if NIPSCO's ECRM Tracker is discontinued, NIPSCO should be prohibited from including such variable operating costs associated with said environmental projects in the calculation of its offer prices when bidding its units into the MISO market.

10. ICC / ICARE Case-in-Chief.

A. Charles S. Griffey. Mr. Griffey testified regarding NIPSCO's 2018 IRP. He stated that the IRP fails to demonstrate that NIPSCO's planned retirements of Schahfer and Bailly are reasonable because NIPSCO created an IRP process using flawed methodology and assumptions, which lead to the conclusion that the coal plants should be retired in the years NIPSCO predetermined.

Mr. Griffey testified against NIPSCO's requests to accelerate depreciation and create a regulatory asset upon retirement of each coal unit. He indicated it is premature for the Commission to determine whether NIPSCO should receive a return on the regulatory asset if it is approved, or what the level of return should be. He testified he takes no position on whether the new market structure and associated cost shift is in the public interest, but he noted that there is no tie between the proposed new structure and the results of the IRP. He stated that because the IRP analysis is significantly flawed, the Commission should postpone any determination regarding rate recovery for the associated plant retirement decisions until after NIPSCO's next IRP.

11. IMUG Case-in-Chief.

A. Theodore Sommer. Mr. Sommer addressed opportunities to collaboratively launch a Municipal Solar Program ("MSP") that would benefit municipalities, their residents, residents in NIPSCO's service area, and NIPSCO and would foster new employment opportunities. He stated the MSP would be designed to maximize benefits for northern Indiana utility regulatory stakeholders. He noted that solar panels could be placed on vacant municipal land, vacant municipal rooftops, blighted land, and brownfields. He explained that participating municipalities would select the available qualifying sites for possible installation of solar panels based upon total value and would have the opportunity to offer solar sites for consideration with NIPSCO. He stated that funding for the MSP panels and installation would be obtained from NIPSCO, a private lender, a private partner, or the municipalities themselves. He indicated there currently is a 30% ITC on the purchase of solar panels suggesting that private financing may be a viable path to capitalization. Mr. Sommer detailed MSP benefits including: (1) new employment opportunities; (2) job training opportunities; (3) Hoosier Homegrown Energy Economic Stimulus; (4) lower purchased power costs for participating municipalities; (5) enhancing public convenience and necessity; (6) environmental benefits and public awareness; and (7) consistency with and promotion of NIPSCO's customer efforts and vision. He testified IMUG is willing to collaboratively work with NIPSCO and others to detail the proposed MSP.

Mr. Sommer had concerns with NIPSCO's proposed streetlight rates with increases of approximately 33% to 49% reflecting NIPSCO's proposed termination of the 50% TDSIC socialization of capital conversion costs for NIPSCO-owned streetlights that have already been

converted to LED. He said that ending the 50% LED retrofit socialization created in the approved seven-year TDSIC plan at this time would result in a shocking LED rate increase to IMUG members. He stated that NIPSCO intends to roll the TDSIC LED street light rate base tracker impacts into rate base as of December 31, 2019. He explained that any streetlight fixtures changed out after the time of that cutoff will be afforded a discounted rate similar to the rate those will have previously experienced. He stated that IMUG municipalities first suggested the LED conversion program, worked to maximize the technical characteristics and economic value of the LED conversion program, and worked to have the LED program approved. However, those municipalities who first converted to LEDs would only receive seven-year TDSIC plan 50% savings for a brief two years and would suffer huge rate increases while those who did not invest the time, effort, and money in the LED program will be converted to LED in the future and will continue to receive the TDSIC socialization or discounted rate on LED converted streetlights for a much longer time period. Mr. Sommer proposed that those with the discounted rate for LED rates continue to be charged the discounted rate following December 31, 2019.

Mr. Sommer proposed that 50% socialization of the converted LED streetlight rate responsibility be allocated to the other customer classes because all people in NIPSCO's service area who travel the roads and sidewalks after dark are the primary beneficiaries of streetlights.

12. Industrial Group Case-in-Chief.

A. Michael P. Gorman. Mr. Gorman testified regarding a number of specific adjustments to NIPSCO's claimed revenue deficiency and supported his recommended return on equity ("ROE") of 9.35%, the midpoint of his recommended range of 9.0%-9.7%.

Mr. Gorman first addressed NIPSCO's proposed treatment of unprotected excess ADIT. He noted that NIPSCO had adjusted its cost of service to reflect the new 21% corporate tax rate implemented by the TCJA and that NIPSCO was proposing to return protected excess ADIT using the average rate assumption method ("ARAM") consistent with IRS normalization rules. Mr. Gorman noted that NIPSCO also proposed using approximately a 15-year ARAM amortization period to return unprotected excess ADIT but a ten-year amortization period for other assets. He recommended using a ten-year amortization period for unprotected excess ADIT. Mr. Gorman explained why he considered NIPSCO's decision to use the ARAM amortization period for unprotected excess ADIT unreasonable and why use of a ten-year amortization period was more appropriate. Based on his recommendation, Mr. Gorman reduced NIPSCO's claimed revenue deficiency by approximately $5.15 million.

Mr. Gorman next recommended reducing NIPSCO's revenue deficiency by approximately $3.32 million to reflect a downward adjustment to its labor expense. He made this adjustment by removing costs associated with unfilled positions from NIPSCO's budgeted headcount.

Mr. Gorman also proposed an adjustment to NIPSCO's proposal to recover a regulatory asset related to the deferral of unrecovered ECR expenses incurred prior to the expected implementation date of new rates. He did not oppose NIPSCO's calculation of the value of the deferred asset at approximately $19.0 million; however, he did oppose NIPSCO's proposal to amortize the expense over a two-year period. Instead, Mr. Gorman proposed to match the

amortization period with the expected life of the rates set in this case, which reduced the annual amortization expense by approximately $4.75 million.

Mr. Gorman proposed removal of contingency costs from NIPSCO's demolition cost estimates for four of its generation stations. Mr. Gorman explained how the inclusion of contingency costs were inappropriate and inflated the demolition cost estimates which, in turn, increased the depreciation rates. Mr. Gorman, therefore, proposed adjusting the depreciation rates on certain accounts, which resulted in a reduction of $2.5 million in depreciation expense. Offsetting this decrease by an increase in operating income and income taxes, Mr. Gorman proposed a net reduction of approximately $2.3 million to NIPSCO's revenue requirement.

Mr. Gorman testified regarding NIPSCO's proposed rate of return and requested ROE. Mr. Gorman began his analysis with a review of general market conditions. He then presented evidence related to the authorized ROEs for electric and gas utilities, the ability of utilities to maintain credit ratings during periods of declining ROEs, and their ability to access external capital to support infrastructure investment under reasonable terms. Mr. Gorman also testified regarding the market's assessment of the investment risk of NIPSCO and its parent company, NiSource.

Mr. Gorman described NIPSCO's proposed capital structure, which reflected approximately 43%:57% debt to equity ratio. He stated this was unreasonable for purposes of setting rates for several reasons. He further testified that using a 50%:50% ratio would, without other adjustments, reduce NIPSCO's requested revenue requirement by approximately $23.4 million. Mr. Gorman noted that a similar reduction would be achieved by reducing the requested ROE from 10.8% to 9.90%.

Mr. Gorman then testified regarding his recommendation for NIPSCO's cost of common equity in light of the Hope and Bluefield standard. He explained the methods used to estimate NIPSCO's cost of common equity, including several variations on the DCF model, the Risk Premium Model, and the CAPM and the inputs he used in applying those models. Based on his analyses, Mr. Gorman recommended a range of 9.0% to 9.7% for NIPSCO's ROE, and he recommended return on common equity of 9.35%. Mr. Gorman testified the 9.35% ROE would support an investment-grade bond rating for NIPSCO.

Finally, Mr. Gorman testified regarding his disagreements with Mr. Rea's approach to calculating NIPSCO's ROE, including the use of a flotation cost adjustment, some of the methods used by Mr. Rea, and various inputs used in conducting his analyses.

B. Nicholas Phillips, Jr. Mr. Phillips agreed with NIPSCO's proposal to use a 4CP method for the allocation of generation investment and 12CP for the allocation of transmission investment in its filed COSS. Mr. Phillips testified that NIPSCO's proposed cost of service method is appropriate and produces fair and reasonable results. He said NIPSCO's COSS is consistent with the cost of service method presented by NIPSCO in its last base rate proceeding. He analyzed NIPSCO's historic monthly peaks in the summer period. He stated the 4CP method properly reflects NIPSCO's historic peaks as well as the forecasts used by NIPSCO for capacity planning. Mr. Phillips also testified that NIPSCO's proposed mitigation plan, which basically sets large industrial loads subject to global competition at cost and increases rates for all other classes

on an "across-the-board" basis, maintaining the current subsidy received by residential customers, has merit, given the circumstances in this case.

Mr. Phillips described NIPSCO's plan to establish Rate 831 for its largest industrial customers as a well thought out solution for the retention of the global manufacturing operations of its largest customers and mitigates NIPSCO's risk of investing in significant amounts of capacity and energy associated with the replacement of its aging generating fleet. He stated that the proposed Rate 831 is a logical extension of the interruptible service option implemented and expanded by the Commission in NIPSCO's last two rate case orders. He added the Rate 831 approach will help retain the large industrial customers, including jobs and tax base, while shielding NIPSCO and its other customers of the obligation to provide firm service to a significant amount of load associated with the Rate 831 customers. He added that NIPSCO's COSS incorporates its proposed rate structure and correctly eliminates the loads for which it will no longer be required to provide generating service.

Mr. Phillips also testified that NIPSCO's proposal to combine the current low load factor Rate 732 and current high load factor Rate 733 into a new Rate 830 for smaller industrial customers results in apparent unintended increases for some customers. Consequently, he recommended the retention of both a low load factor rate and high load factor rate for those current customers receiving service on Rate 732 and Rate 733 that are not opting, or are not eligible, for Rate 831 service. He noted NIPSCO has offered a low load factor rate and a high load factor rate to its customers for decades and those offerings should not be discontinued. Mr. Phillips also recommended that NIPSCO implement a voltage adjusted fuel factor to more accurately reflect the cost to serve customers at varying voltage levels.

C. James R. Dauphinais. Mr. Dauphinais testified in support of the proposed Rate 831 rate structure. He supported NIPSCO's decision as a prudent judgment in light of the risk that large industrial load will continue to leave the NIPSCO system through self-generation, closures, or shifting production to other locations. He stated NIPSCO's largest customers use energy-intensive processes and are subject to intense competition, and Rate 831 would allow those customers greater ability to manage power costs and risks. He described Rate 831 as a logical evolution of existing options. He also stated that Rate 831 would be beneficial to other rate classes by addressing the risk of continued reductions in large industrial load, while better allowing NIPSCO to "right size" its generation resources and avoid excess capacity.

Mr. Dauphinais explained the structure of Rate 831 and the distinct features of Tiers 1, 2, and 3 as well as Rider 876. He proposed an amendment to tariff language to address a proposed MISO change, and a revision to the proposed definition of an industrial "Premise" in light of a then-pending dispute with a large customer.

13. NLMK Case-in-Chief.

A. James A. Lahtinen. Mr. Lahtinen testified in support of the proposed new industrial rate structure. Mr. Lahtinen explained that NIPSCO correctly discerned that basic changes in energy market place fundamentals including that sustainable supplies of domestically sourced natural gas have enhanced the attractiveness of self-supply alternatives for NIPSCO's largest industrial customers. Given NIPSCO's dependence on industrial customers and energy

intensive, competitively at-risk manufacturing facilities for a very large component of its retail electric sales, NIPSCO was compelled to respond constructively to the potential loss of industrial load to on-site generation bypass or production relocation. Based on his previous experience with industrial load loss in Pennsylvania in the 1980s, Mr. Lahtinen commended NIPSCO for proactively developing constructive solutions to retain its largest industrial loads.

Mr. Lahtinen explained that under Rate 831, it was essential that the firm, Tier 1 rates be reasonable for the rate structure to be feasible. He emphasized that the proposed Tier 1 demand charges will be significantly higher than current rates, especially for customers served on current Rate 732, and that it was imperative that Rate 831 rates be designed to provide a rate of return that did not exceed the system average return. Mr. Lahtinen found that NIPSCO's proposed use of a 4CP allocation method for its production plant was reasonable and consistent with cost causation principles given the strong summer peaking nature of NIPSCO's system. Mr. Lahtinen acknowledged that there was substantial uncertainty regarding the amount of Rate 831 load that would be enrolled as firm, Tier 1 service for the first five-year contract term, and that a shortfall in Tier 1 enrollment could have material rate consequences for other customers. Mr. Lahtinen recommended that this uncertainty be resolved in part by increasing the required minimum level of Tier 1 service to the lesser of a customer's historic level of firm service or 30,000 kW.

Noting that under prevailing Rider 775, existing interruptible industrial loads that elect to "buy-through" economic interruptions are charged spot wholesale energy prices, Mr. Lahtinen concluded that the proposal in Rate 831 to expand that buy-through concept to all large industrial non-firm load, which would remain LMRs, was a reasonable approach. He further concluded that the mechanisms that NIPSCO proposed for Tiers 2 and 3 of Rate 831 non-firm service provided the tools reasonably necessary for Rate 831 customers to manage their energy price risk exposure.

Mr. Lahtinen concluded that NIPSCO's proposal to set the Rate 831 revenue requirement based on the cost of service while applying an across the board equal percentage increase to all other rate classes was a balanced and thoughtful approach for re-aligning industrial rates at cost while mitigating the rate impacts on other customers, particularly the residential class. If the Commission determined not to adopt the proposed industrial rate structure, Mr. Lahtinen maintained that the existing industrial rate structure and interruptible Rider 775 should be retained.

14. Peabody Case-in-Chief.

A. Michael J. Nasi. Mr. Nasi testified that NIPSCO's assumed regulatory timelines for compliance with the EPA's CCR Rule and the ELG Rule were too short because of available extension options and EPA's plans to reform both rules. He stated that NIPSCO's estimated capital expenditure and O&M costs were either not backed up by specifics or simply too high. This includes costs for compliance with the CCR Rule, ELG Rule, the CSAPR, and the MATS Rule. He also challenged NIPSCO's retirement decisions based on: (1) inclusion and accuracy of capital and O&M costs for continuing operations and compliance with environmental regulations to justify retirement decisions; and (2) NIPSCO's assumption that both ELG and CCR costs will be incurred regardless of whether the units continue to operate.

Regarding the ELG Rule, Mr. Nasi stated that NIPSCO overestimated the cost of compliance based on the current postponement of certain compliance dates and EPA's intent to

revise the ELG Rule by December 2019. He further claimed there were "discrepancies" in NIPSCO's cost estimates and "uncertainties" in the status of the ELG Rule that suggest NIPSCO's request to be unreasonable and imprudent. He stated that there was an unexplained mismatch between certain ELG compliance costs and that NIPSCO should have advocated for broader ELG Rule changes because further ELG Rule changes could potentially be taken up by EPA.

Regarding the CCR Rule, Mr. Nasi testified that NIPSCO overestimated compliance costs, which are estimated to be $226 million, as provided in discovery by NIPSCO. After discussing the background and status of the CCR Rule, including a recent court decision, he opined that he did not agree that NIPSCO's estimated CCR costs within its IRP are reasonable and prudent. He also discussed the AROs and asserted this information was included in Mr. Carmichael's testimony to establish additional justification for NIPSCO's proposed retirement decisions.

As related to MATS Rule compliance, Mr. Nasi stated that it is inappropriate for NIPSCO to continue assuming it will incur long-term MATS O&M costs for its generating units because there is a significant likelihood that EPA will withdraw MATS entirely or drastically alter the rule thereby reducing the ongoing O&M cost burden. He testified that incorporation of "high O&M costs into [NIPSCO's 2018] IRP" is unreasonable because the EPA announced reconsideration of the MATS rule in August 2018 and proposed a revised supplemental cost finding in December.

Mr. Nasi also raised criticism of NIPSCO's proposed compliance path for CSAPR. His primary criticism was that NIPSCO failed to provide adequate justification for selecting SCR technology over the less costly, alternative selective non-catalytic reduction ("SNCR") technology. He stated that there is no reasonable set of assumptions that could justify NIPSCO's assumed SCR expenditure. He also took issue with the responses NIPSCO provided to Peabody Requests 1-010 and 1-011 (included as Attachment Nos. MJN-5 and MJN-6), wherein NIPSCO explained why it had assumed SCR technology for compliance with CSAPR.

15. Sierra Club Case-in-Chief.

A. Avi Allison. Mr. Allison's primary findings can be summarized as follows: (1) NIPSCO's proposal to increase the residential customer charge is based on a flawed theoretical construct that, if following to its logical conclusion, would ultimately result in a residential customer charger greater than $100 per month; (2) NIPSCO's residential customer charge proposal is inconsistent with sound ratemaking principles and would negatively impact energy conservation efforts and low-income customers and that a reasonable residential customer charge would be lower, not higher, than the current NIPSCO customer charge; (3) NIPSCO has failed to provide sufficient justification for its proposed new industrial service structure that would shift at least $40 million in annual costs from industrial customers to other customer classes; (4) the proposed industrial service structure change is not aligned with NIPSCO's IRP load assumptions; and (5) NIPSCO's proposal to depreciate its remaining coal plants through 2030 strikes a reasonable balance between aligning asset recovery with asset life and minimizing near-term rate shock.

Mr. Allison recommended: (1) the Commission should reject NIPSCO's proposed increase in the residential customer charge and instead lower the residential customer charge to no greater than $12.77 per month and reject the use of a "straight-fixed variable" ("SFV") rate design as a reasonable basis for determining an appropriate residential customer charge; (2) the Commission

should reject the proposed allocation of costs under the new industrial service structure and that given the massive rate impacts on other customer classes, the Commission should not approve the proposal without concrete evidence of substantial, imminent defections by industrial load; (3) if the Commission approves of the general framework of the new service structure, it should still require that NIPSCO allocate a larger portion of its historical fixed costs to industrial customers, as those costs were incurred to serve industrial customers' historical load; (4) if the Commission approves the proposed industrial service structure change, it should require that all future NIPSCO IRP load forecasts account for any reductions in the reduced industrial demand associated with the new service structure; and (5) the Commission should approve NIPSCO's plan to recover the remaining depreciation expenses associated with Schahfer and Michigan City through 2030; however, this approval should not imply pre-approval of specific investments at those plants and should be contingent on NIPSCO following through with its planned coal plant retirement dates.

16. Walmart Case-in-Chief.

A. Steve W. Chriss. Mr. Chriss testified on cost of service issues, revenue allocation, and rate design, including NIPSCO's proposed Rate 831 structure. Specifically, Mr. Chriss advocated that rates be set based on the utility's cost of service for each rate class and that regulatory policies should be set that support the fair-cost-apportionment objective of rate-making, ensuring that rates reflect cost causation. As Mr. Chriss noted, this sends proper price signals to customers and minimizes price distortions.

Mr. Chriss discussed Walmart's concerns with discrepancies in NIPSCO's COSS that impacted the accuracy of assigning overall costs to the customer classes and establishing the cost-basis for the proposed rates, particularly for NIPSCO's Off-Peak Service class on Rate 726, when evaluated in comparison with NIPSCO's COSS filed in the last base rate case. These discrepancies indicated errors with the load characteristics and billing determinants for the Off-Peak Service class. Mr. Chriss explained these errors produced a misinformed revenue allocation in NIPSCO's COSS that understated revenues associated with the Off-Peak Service class and misrepresented the class's contribution to its cost to serve, as depicted by the Index Rate of Return. However, he stated these errors also impacted NIPSCO's representation of the system's overall "subsidy" position between the various classes. Mr. Chriss further noted that the errors contained in the COSS impact the proper rate design for the Off-Peak Service class by producing overstated prices, which would then lead to excess revenues being collected from the class. As such, Mr. Chriss recommended that the Commission reject NIPSCO's COSS because it would lead to rates that are not just and reasonable and would impact the Commission's assessment of the interests of all NIPSCO customers when reviewing the Rate 831 structure proposed for the industrial class.

Mr. Chriss provided his assessment of NIPSCO's proposed allocation of revenues. He stated that by designing Rate 831 at cost and then assigning an equal percentage increase to all other classes, rates were produced that moved all classes further from their actual cost to serve, which is counter to the goal of eliminating or establishing a targeted reduction of subsidies for all classes. As such, Mr. Chriss recommended that the Commission reject NIPSCO's proposed revenue allocation and instead allocate the authorized revenue in a manner that targets and reduces the subsidy burden for all subsidizing classes. Mr. Chriss noted that this could be done by ordering an increase to subsidizing classes that is lower than the system average increase coupled with an

increase to subsidized classes that is above the system average without causing an unduly burdensome rate increase on any class.

Regarding the Rate 831 proposal, Mr. Chriss noted Walmart's concerns that the proposed alternative regulation for this limited class of industrial customers would result in: (1) an unjust shift in cost responsibility from NIPSCO's largest industrial customers to the remaining customers by assigning capacity obligations that are not related to non-Rate 831 customers' actual capacity requirements; (2) the establishment of customer access to the wholesale market, which fails to properly assign transition costs to the departing load; and (3) eligibility requirements that appear to be unduly discriminatory insofar as they exclude other large, sophisticated customers that might also benefit from market access rates. Mr. Chriss recommended that the Commission reject the Rate 831 proposal. However, if the Commission determines that the threat of reduced industrial load warrants immediate action, Mr. Chriss recommended that the Commission establish a solution that addresses the immediate concerns while also addressing the proposed burden on the remaining customers. Mr. Chriss cited to a California state law that requires customers who take service through third-party energy providers to pay a power charge indifference adjustment or an exit fee to ensure that remaining customers are not left with the responsibility to pay transition costs that should be the responsibility of the departing customers.

On July 17, 2019, as requested by the Commission in its July 16, 2019 Docket Entry, Mr. Chriss updated Exhibit SWC-3, an attachment to his prefiled direct testimony. As updated, Exhibit SWC-3 (REVISED) contains a listing and various averages of authorized ROEs in electric utility rate cases ranging from 2016 through July 10, 2019. In particular, the document indicates that the average ROE for vertically integrated electric utilities for the entire period is 9.73% and the average ROE for vertically integrated electric utilities solely for 2019 is also 9.73%.

17. US Steel Case-in-Chief.

A. Brown D. Thornton. Mr. Thornton testified on behalf of US Steel's support of the Rate 831 structure. He identified several aspects of the Rate 831 structure that need to be clarified or resolved prior to its implementation. First, Mr. Thornton recommended that Rate 831 have a phase-in period for customers between the final order in this Cause and May 31, 2020, to coincide with MISO's planning year. Second, he testified that Rate 831 customers should only be financially obligated to either NIPSCO or a third party for the same energy and capacity. Third, Mr. Thornton stated that the Rate 831 tariff should better define NIPSCO's role in the event a Rate 831 customer disputes any MISO charge. Fourth, Mr. Thornton recommended that between the final order and May 31, 2020, NIPSCO and the Rate 831 customers develop a model third-party agreement to govern when a Rate 831 customer remains a retail customer of NIPSCO while contracting for part of its power supply with a third party. Finally, Mr. Thornton recommended that the Rate 831 tariff allow capacity purchases outside of MISO Zone 6 so long as firm capacity is deliverable into Zone 6 to meet MISO's Module E requirements. Ultimately, Mr. Thornton recommended approval of Rate 831 because it provides long-term benefits to NIPSCO's customers by reducing risks for NIPSCO and its customers and ensuring that NIPSCO's largest customers continue to contribute to NIPSCO's fixed costs.

B. Tony M. Georgis. Mr. Georgis testified that US Steel operates three large steel manufacturing and finishing plants in NIPSCO's territory. US Steel is estimated to have a

$55.9 billion total impact on the Indiana economy and is one of NIPSCO's largest customers. Mr. Georgis explained that US Steel is very sensitive to NIPSCO's power prices due largely to international price competition for steel. He testified that in the absence of Rate 831, US Steel may explore other power supply options to significantly reduce US Steel's reliance on NIPSCO through self-built cogeneration that US Steel could certify to FERC as a QF. Mr. Georgis stated that if US Steel leaves the NIPSCO system entirely, the remaining NIPSCO customers would pay the fixed costs currently paid by US Steel, which he estimated at between $17 to $20 million annually, which include labor, depreciation, and other capital costs that do not vary with energy sales.

Mr. Georgis testified that Rate 831 is a natural evolution from NIPSCO's current interruptible service offerings. He recommended that the Commission approve Rate 831 and noted that it benefits other customer classes by simultaneously addressing the needs of NIPSCO's largest industrial customers while ensuring that NIPSCO's remaining customers will not be responsible for replacement generation costs to serve industrial load that is more volatile and able to leave the system with stranded cost. Mr. Georgis recommended adjustments to NIPSCO's over-allocation of transmission costs to the 831 rate class and recommended that NIPSCO subfunctionalize transmission rates for 831 customers to accurately reflect the service voltage levels at which 831 customers receive service. Mr. Georgis also recommended that NIPSCO clarify the firm demand rate calculation and true-up process to be used to ensure that the Rate 831 customers' Tier 1 firm capacity elections meet or exceed the 184,556 kW that NIPSCO proposed to allocate to Tier 1.

18. Cross-Answering Testimony.

A. CAC. Dr. Stanton recommended that the Commission not credit the critiques of NIPSCO's 2018 IRP advanced by ICC witness Medine, ICARE witness Griffey, and Peabody witness Nasi. She found that NIPSCO made significant improvements between its 2016 and 2018 IRPs by conducting an all-source RFP reviewed and improved upon by stakeholders, increasing transparency of modeling data and commodity price forecasts, removing arbitrary limits and unsupported cost additions on renewable resource choices, and addressing other criticisms of its 2016 IRP.

Dr. Stanton stated that although NIPSCO should have modeled a specific representation of Rate 831 industrial load reduction in the IRP as Ms. Medine stressed, the IRP results demonstrate that this modeling very likely would not have changed the order of preference of NIPSCO's portfolios. If anything, an industrial load reduction would have favored earlier retirement of all NIPSCO's coal units (Retirement Portfolio 8) even more strongly. Dr. Stanton explained that Ms. Medine failed to explain or quantify her implied suggestion that NIPSCO should take measures to improve forced outage rates and lower O&M costs at NIPSCO's coal plants or otherwise justify continued use of these coal units. Dr. Stanton also stated that Ms. Medine highlighted the alternative scenarios produced at ICC's request, which included several assumptions favoring delayed coal unit retirements. However, these alternative scenarios were still more expensive than Portfolio 6 and Portfolio 8 and therefore, support NIPSCO's decision to retire all of these units.

Dr. Stanton testified that Mr. Griffey's claims of a solar capital cost bias very likely would not have changed the rank of the eight portfolios by cost or changed the IRP modeling conclusion to retire all coal units. She stated that Mr. Griffey claimed that NIPSCO should have included projected degradation of wind generation into the model. This projected degradation would only

affect wind resources owned by NIPSCO, not resources where NIPSCO has a PPA with the resource owner, who has the onus to maintain the facility. She explained that projected degradation is irrelevant in this case because NIPSCO has or will have a PPA for most of the wind resources currently owned by NIPSCO and offered in response to NIPSCO's RFP.

Dr. Stanton stated that Mr. Griffey argued that NIPSCO should have conducted retirement optimization modeling with NIPSCO's actual replacement portfolios. However, she explained that this very likely would not have changed the selection of Retirement Portfolio 6 as the preferred retirement portfolio. She also stated that Mr. Griffey incorrectly contrasted intermittent renewable generation with dispatchable resources in MISO. She then addressed Mr. Griffey claim that Indiana's wind effective load carrying capability ("ELCC") is lower than other states. NIPSCO's current wind generation does not originate in Indiana, and given the wind bids from multiple states responding to NIPSCO's 2018 RFP, NIPSCO's wind additions cannot be assumed to come entirely from Indiana. She explained that NIPSCO's use of the MISO average ELCC in its modeling, rather than the Indiana wind ELCC, was reasonable.

Finally, Dr. Stanton stated that Mr. Nasi provided no reason for NIPSCO to assume that the MATS rule would be delayed or discontinued.

B. ICC. Mr. Graeter responded to Sierra Club witness Allison's agreement with NIPSCO's underlying decision to accelerate the retirement of Michigan City and Schahfer due to the likely savings shown in NIPSCO's IRP retirement analysis because the calculation of savings Mr. Allison references does not take into account the cost of lost jobs that accelerated retirements could cause. Mr. Graeter performed a Job Impact Study of the Accelerated Retirements of NIPSCO's R.M. Schahfer and Michigan City Power Plants showing that the accelerated retirements will have serious negative impacts on the local communities, while NIPSCO's plan to replace these power plants will do little to soften these impacts.

C. ICARE. Mr. Griffey disagreed with Sierra Club witness Allison's conclusion that any potential loss of industrial firm load (due to the proposed industrial service structure or other causes) would likely render NIPSCO's coal units even less viable than they were found to be in the IRP retirement analysis because maintaining flexibility about when to retire the coal plants and deferring burdensome new PPAs or renewables ownership is likely to have great value. He also disagreed with Mr. Allison's agreement with NIPSCO that retiring Schahfer in 2023 and Michigan City in 2028 will likely save NIPSCO's customers more than $4 billion in NPV terms relative to continuing to operate the units because the savings are illusory as NIPSCO only made assumptions and ran the Aurora model for 20 years, yet made 30-year NPV calculations.

Mr. Griffey concluded that if his critique of wind resources is proven correct as to such items as unforced capacity ("UCAP") and congestion costs, it means that NIPSCO's failure to accurately model wind resources in its IRP renders the IRP results useless for decision making.

D. Industrial Group. Mr. Dauphinais disagreed with testimony suggesting that Rate 831 inappropriately shifted costs to other customers and with the proposal for transition charges or exit fees for Rate 831 customers. He stated that Rate 831 is a cost-based rate, and the costs incurred by NIPSCO to provide that service are less only because less system resources are being used. He indicated the proposed transition charges would force Rate 831 customers to cover

costs for system resources no longer being used to provide them with service, while also leaving them with cost responsibility for market resources actually used to meet their power needs and the associated market risk.

Mr. Dauphinais disputed the computation of $40.2 million in shifted costs from Rate 831 customers to other customers. He stated that figure does not account for additional OSS margins that NIPSCO will earn and pass through to customers as a result of not serving Tiers 2 and 3 load at average fuel cost, which he calculated as $9.9 million annually. He identified further reductions in price volatility to other customers. He emphasized that, without Rate 831, NIPSCO is at great risk of losing large industrial load due to self-generation, shutdown of facilities, or reduced production. Consequently, lost revenue from those customers could greatly exceed the computation of shifted costs.

Mr. Dauphinais testified the proposed transition charges or exit fees were inappropriate. He stated such charges have not been imposed on customers exercising their right to self-generate or shut down facilities, and it would be misguided to apply such charges here to customers that use self-generation, may use self-generation, or reduce production but for Rate 831. Describing Rate 831 as an initiative to retain at-risk load, he stated the proposed transition charges would undermine that objective and exacerbate the risk. He cited a FERC regulation that permitted recovery of stranded costs only where there was "a reasonable expectation that the utility would continue to serve the customer," an essential predicate absent here. He stated Rate 831 is not retail wheeling, differs in multiple respects from an open access structure, and is supported by the provisions and legislative policy of the Alternative Utility Regulation Act ("ARP Statute"), Ind. Code ch. 8-1-2.5.

Mr. Dauphinais disagreed with the suggestion that NIPSCO's proposed transmission charge should be revised in connection with backing up the self-generation facilities of Rate 831 customers. He stated the transmission rate for back-up service as proposed by NIPSCO was consistent with cost-causation, traditional cost allocation, FERC and Commission rules, and NIPSCO's existing back-up rate. The suggested increase through added demand charges would erect barriers to highly efficient self-generation, contrary to Indiana and Federal policy. He noted NIPSCO allocated transmission costs based on monthly coincident peak demand, not energy, and therefore use of an energy charge will affect only collections from individual customers within the Rate 831 class, with no impact on other classes. He further stated that NIPSCO's allocation of transmission costs is consistent with MISO's current and expected future practices. He cited FERC and Commission rules providing that back-up rates should not be based on an assumption that outages for self-generation facilities on a utility's system will all occur simultaneously, or at system peak, or both, and the addition of demand charges would be inconsistent with those rules.

Mr. Dauphinais also took issue with a proposal that Rate 831 contracts should be exempt from NIPSCO's general rule terminating contracts in the event of a rate case, stating it would be unreasonable to bind a customer to a contract even if a rate case changes the terms and conditions of Rate 831. He further addressed a challenge to a provision in Rate 831 allowing for a reduction in firm demand for closure or partial closure of a customer facility, stating it would be unreasonable to require continued contractual service at the same level when the load being served has significantly changed. Finally, Mr. Dauphinais responded to alternative approaches suggested in the event that actual subscriptions for Tier 1 service end up falling significantly below the

projections assumed by NIPSCO, stating the better alternative would be to establish a process to determine Tier 1 demand if and when any shortfall occurs.

Mr. Phillips testified that the concept of legacy costs and a transition charge is fraught with problems, constitutes unreasonable ratemaking, and should be rejected. He explained that the concept assumes industrial customers have not already paid a fair portion of the costs associated with the generation costs and have not saved other customers the avoided costs associated with new generation through self-supply or by accepting the risk of interruptible load.

Mr. Phillips testified that NIPSCO's current coal fleet was constructed between 33 and 45 years ago and that no customer is obligated to support costs for that duration. He said NIPSCO has not planned or constructed a baseload coal-fired generating facility in approximately 50 years and that NIPSCO has already closed two generating stations (Mitchell and Bailly) for various reasons, and NIPSCO plans on closing the remaining facilities in the near future. Mr. Phillips added that industrial customers have mitigated NIPSCO's need to add generation by taking interruptible service and investing in self-generation. He said the U.S. Department of Energy's list of combined heat and power installations in Indiana shows more than 1,300 MW of installed capacity at industrial plants in NIPSCO's territory. Mr. Phillips testified that all of NIPSCO's customers have benefitted historically due to the large industrials' acceptance of interruptible risk and private investment in self-generation, which resulted in less system resources NIPSCO had to build and maintain. He said it would be unbalanced and unreasonable to require those same customers to bear legacy costs. Mr. Phillips testified that customers of all classes are free to lower load, self-generate, or leave a service territory and said it is not appropriate to claim legacy costs from previous decades through a transition charge associated with load reduction.

In response to claims that the Rate 831 customers would be getting a subsidy, Mr. Phillips first noted that under NIPSCO's COSS, production costs are allocated to the Rate 831 customers based on the amount of capacity NIPSCO estimated they would use, which is cost-based ratemaking, not a subsidy. He also provided a history of the subsidies industrial customers have provided to other customer classes since NIPSCO's 1981 rate case. He calculated the subsidies the industrial customers have provided to other customer classes totaled $2.85 billion over the 20-year period from 1987 to NIPSCO's 2008 rate case. Conservatively, Mr. Phillips noted if the calculated subsidies were cut in half, $1.4 billion would still greatly exceed the alleged legacy costs. Consequently, due to the subsidies, large industrials have been paying revenue far in excess of their cost-based share and that excess revenue is much greater than the alleged legacy costs that the other witnesses propose to impose as a transition charge on Rate 831 customers.

Mr. Phillips also took issue with NIPSCO's response to CAC's DR 5-1, upon which Mr. Wallach relied. Mr. Phillips stated that the response inappropriately allocated fixed generation costs to interruptible load. He provided a correction that removed interruptible load from the four highest peaks to recalculate a normalized 4CP allocator. He stated the 2017 load data associated with interruptions used in the response is not normalized or indicative of the 2019 test year.

Mr. Phillips also responded to Mr. Watkins' comparison of the 4CP allocation percentages used in NIPSCO's last rate case to the allocation percentages used in this case. According to Mr. Phillips, there are two significant problems with the comparison. First, the loads in the current case

are reduced because of the lost BP load. Second, the loads used in the last rate case included interruptible load, whereas the current case only uses firm load for allocating production costs.

Mr. Phillips also addressed Mr. Watkins' alternative cost allocation methods, noting that to his knowledge, the Commission has never approved an allocation method that classifies and allocates production investment costs on an energy basis. Mr. Phillips described the problems with the various methodologies that Mr. Watkins discussed and noted that not only is the 12CP method not reflective of the cost causation on NIPSCO's system, but that many of the 12 monthly peaks contain buy-through loads by customers on Rider 775. He explained those buy-through loads should not be used to allocate production costs because NIPSCO does not plan for or build generation for interruptible load, and the interruptible customers have obtained the power from the market. He then recommend use of the 4CP method because it is most reflective of cost causation.

E. NLMK. Mr. Lahtinen reiterated that the 4CP allocation method proposed by NIPSCO was reasonable and appropriate considering the NIPSCO system load profile, and that the more energy-oriented alternative methods described by OUCC witness Watkins would undercut the basic purpose of the proposed industrial rate restructuring by unnecessarily shifting costs to large industrial loads. Mr. Lahtinen urged the Commission not to adopt such a counter-productive approach. Similarly, he urged the Commission to reject the "transition cost" proposals advanced by the OUCC and CAC. He observed that industrial rates have historically subsidized the rates of smaller consumers, and that setting Rate 831 to recover the system average return (i.e., to set the rate at "parity") is an essential element to combatting uneconomic industrial customer bypass. Mr. Lahtinen explained that, by proposing the imposition of a Rate 831 transition fee, those parties were espousing an extension of the inter-class subsidies that would produce rates for large industrial customers that might accelerate rather than deter bypass actions.

Mr. Lahtinen explained why the US Steel proposal to create voltage differentiated transmission charges within Rate 831 was problematic, insufficiently supported, and should not be adopted. He also explained that the provisions of the Rate 831 tariff that would extinguish Rate 831 contracts under certain circumstances were reasonable and necessary, and the concerns expressed by the OUCC in that regard were unwarranted.

F. Sierra Club. Mr. Allison responded to ICC witness Medine, ICARE witness Griffey, and Peabody witness Nasi, who argued that NIPSCO should not move forward with its plans to retire its coal units. Mr. Allison showed that the arguments of these witnesses are rooted in a series of inaccurate assumptions, mischaracterizations, and misleading statements.

He stated that NIPSCO's remaining coal units have been uneconomic (i.e., more expensive than available alternatives) for many years now. Contrary to the implication of the coal industry witnesses, these are not currently well performing units that will only become uneconomic if faced with substantial environmental compliance obligations. Rather, are units are already and continue to be a consistent economic burden for NIPSCO's ratepayers. He estimated that each remaining NIPSCO coal unit lost more than $100 million relative to the market from 2014 through 2018.

Mr. Allison explained that NIPSCO's coal units are likely to remain uneconomic irrespective of any environmental capital expenditures. Even if these units do not need to incur any expenses to comply with CCR regulations, ELG, or other federal environmental regulations,

near-term retirement would still be in the best interest of NIPSCO's customers because NIPSCO's coal units are already more costly than available alternatives. NIPSCO data indicates that, even in the absence of any environmental capital expenditures, continuing to operate its coal units would result in billions of dollars in NPV losses relative to alternative resources.

Mr. Allison stated Mr. Griffey's claim that NIPSCO's IRP analysis supports the continued operation of Michigan City Unit 12 is false and is rooted in a plainly misleading comparison. He explained that NIPSCO's analysis clearly indicates that retiring Michigan City in the near term would save ratepayers hundreds of millions of dollars. He also stated that Mr. Griffey's claim that it is not in the interest of ratepayers to retire Schahfer Units 14 and 15 in the near term is refuted by his own analysis. Mr. Griffey's analysis indicates that, even under a host of assumptions that are favorable to NIPSCO's coal units, retiring Schahfer Units 14 and 15 in 2023 rather than 2028 would save ratepayers more than $200 million. Mr. Allison testified that Mr. Griffey misstated the potential retirement dates considered by NIPSCO. He explained that the actual retirement dates evaluated by NIPSCO consistently show that retiring NIPSCO's coal units as early as possible is always the lower-cost choice, even in the absence of environmental expenditures.

Mr. Allison stated that Ms. Medine's suggestion that it was unreasonable for NIPSCO to include a carbon price in its base scenario is unpersuasive and is inconsistent with the practices of other Indiana utilities. He also stated that Ms. Medine's suggestion that keeping NIPSCO's coal units online longer will minimize rate shock is unsupported.

Mr. Allison testified that Mr. Nasi's claims that NIPSCO's retirement decisions improperly rely on CCR-related costs that will be incurred regardless of future retirement decisions are unsupported and baseless. He explained that uncertainty does not constitute a valid reason to delay a decision to retire the NIPSCO coal units. While uncertainty is inevitable in any major resource planning decision, the available evidence strongly supports the near-term retirement of NIPSCO's coal units. He added that NIPSCO's proposed industrial service structure change does not justify delaying coal unit retirement decisions.

Mr. Allison testified that fundamentally, the available evidence clearly indicates that NIPSCO's coal units are currently uneconomic and are very likely to remain that way. He concluded that NIPSCO should retire its remaining coal units as soon as is practicable and recommended that the Commission approve reasonable ratemaking treatment that will enable these retirements and their attendant ratepayer benefits.

G. US Steel. Mr. Georgis refuted claims that Rate 831 creates a cost shift to non-Rate 831 customer classes, explaining that presently a subsidy is built into the existing rate structure whereby Rate 831 customers pay disproportionately to the benefit of the remaining customer classes. Mr. Georgis explained that if Rate 831 customers were required to pay an annual $40.2 million transition charge as recommended by other parties, Rate 831 customers would be paying for infrastructure and services they do not use or receive any benefit. Mr. Georgis testified that a $40.2 million subsidization is not cost based, does not follow cost of service principles, and is inconsistent with NIPSCO's treatment of similar customers who reduce demand or generate all or a portion of their power. Mr. Georgis also refuted the OUCC's recommended transmission charge adjustment, noting that the Rate 831 customers should not be forced to purchase back-up and maintenance transmission service embedded in the Rate 831 transmission charges if the

customer accepts the risks and consequences associated with their self-generation, especially since customers desiring back-up and maintenance service can obtain it through Rider 876.

Mr. Georgis agreed with NIPSCO's 4CP allocation of production costs since the system is consistently a summer peaking system, which drives NIPSCO's production capacity investments. He reiterated that US Steel continues to actively evaluate additional cogeneration potential and although it withdrew its IDEM permit application pending the outcome of this proceeding, it has not foreclosed building cogeneration in the future. Mr. Georgis disagreed with Dr. Boerger's recommendation for a full adjudicated process for Phase 2 of the proceeding since the Phase 2 issues are limited in scope. Finally, Mr. Georgis recommended that the Rate 831 customers should decide amongst themselves how the $53.9 million of Tier 1 firm contract demand costs should be recovered, which eliminates the unintended consequence that penalizes one or more customers.

19. NIPSCO Rebuttal Evidence.

A. Mr. Hooper. Mr. Hooper addressed the other parties' testimony related to Rate 831, the OUCC's proposed credit mechanism to address return on and of unrecovered balances upon the retirement of Schahfer and Michigan City generating units, CAC's proposal for a comprehensive low-income program and various monthly reporting requirements, and IMUG's proposal to implement an MSP. He testified that NIPSCO believes a migration of load to either self-generation or other jurisdictions for much of its largest industrial load is imminent without a modification to a more competitive service structure as evidenced by discussions with and filings made by those customers supporting the intent to add or increase self-generation. He stated that a combination of these customer's scale, generation experience, and energy market sophistication make them uniquely positioned to take advantage of a proposal such as Rate 831. Likewise, those same traits are sufficient to motivate these customers to either shift operations or invest in additional generation assets when faced with inferior economics from NIPSCO's fleet.

Mr. Hooper disagreed with Mr. Blakley's proposed mechanism in which ratepayers are credited with the effect of annual depreciation expense associated with these extraordinary retirements beginning when new rates go into effect and prior to the units actual retirement dates. He stated that the OUCC and other parties consistently make the mistake of calling NIPSCO's extended recovery period for its retiring coal units as "accelerated" deprecation – which is not true. He noted that were NIPSCO to recover its remaining investments over the remaining useful life of these units, NIPSCO's depreciation rates would be much higher, resulting in a much higher revenue requirement. Instead, NIPSCO is proposing to extend its recovery period to ten years to reduce the rate impact. He also disagreed with OUCC suggestion that its "tracker mechanism" be put in place prior to the retirement date of the Schahfer units. He explained that if a capital tracker was approved, it should not be utilized solely for a one line item, but should allow for the recovery of all additional capital deployed during the recovery period.

In response to CAC's proposal for a comprehensive low-income program, Mr. Hooper testified that NIPSCO wants to implement a proposal that is easily and economically administered that can provide assistance to the most in need. He stated NIPSCO recognizes the demographics of its service territory and recognizes that while it offers a low-income program to its LIHEAP-qualified customers that heat with gas, it offers no additional programs for its LIHEAP electric

heating customers. He stated NIPSCO is continuing a stakeholder collaborative to reach agreement regarding additional assistance that can be offered to NIPSCO's low-income customers.

Mr. Hooper disagreed with CAC's recommendation for various monthly reporting requirements. He stated that NIPSCO already participates in an annual Performance Metric Collaborative where it reports on and discusses a host of key performance indicators. He indicated that in the Performance Metric Collaborative report filed by July 1 each year in Cause No. 44688, NIPSCO already provides monthly data for some of the items recommended by Mr. Howat and that additional items recommended by Mr. Howat could possibly be incorporated into the annual report without the added administrative burden that would be required if a separate monthly reporting process were implemented here.

Mr. Hooper agreed that IMUG's proposal to implement an MSP is worth further investigation. He stated, however, this is a program that would need substantial discussion amongst NIPSCO and interested parties. He explained that NIPSCO is willing to work collaboratively with IMUG to discuss the MSP and determine if such a program may fit into its existing generation portfolio. He stated that while he agrees with Mr. Sommer that an MSP could prove beneficial to many stakeholders, it is simply an idea that needs further vetting to ensure the appropriate parties are engaged and all aspects are thoroughly understood.

B. Mr. Kelly. Mr. Kelly stated that while Rate 830 is designed to provide service for NIPSCO's next largest group of industrial customers after Rate 831, the proposed rate is structured for a higher load factor profile. For the lower load factor customers within the rate design, it is likely that their increases would be higher than if the original designs of Rate 732 and 733 had been preserved. Mr. Kelly agreed with Mr. Phillips' recommendation that Rate 830 should be redesigned into two rates similar to the existing Rates 732 and 733. He testified NIPSCO is offering proposed Rates 832 and 833, which are designed as low load factor and high load factor rates similar to Rates 732 and 733. He explained that like the original Rate 830 proposed design, these proposed rates also include provisions for Back-Up, Maintenance, and Temporary Service.

Mr. Kelly testified Rate 831 retains retail service and is therefore not a retail wheeling or retail open access proposal and should not be rejected as incongruent with Indiana law or for failing to meet the requirement that NIPSCO provide retail utility service to its customers, as suggested by Ms. Medine. He stated Rate 831 preserves the bundled retail electric service these customers are served under today's Rates 732, 733, and 734 as well as the ability to purchase power at the MISO LMP during Rider 775 economic interruptions. He explained that Rate 831 only adds two additional features to NIPSCO's existing large industrial service structure: (1) the ability to firm up the customer's LMR obligation registered at MISO through the MISO capacity auction or a third party; and (2) the ability to bid a portion of the customer's load in the MISO portal (granted by NIPSCO) or purchase that portion of its energy from a third-party supplier. To accomplish these new options, NIPSCO still needs to facilitate the transactions as the MISO Market Participant whether by making the necessary registrations or by entering multiparty agreements for the benefit of the customer for capacity or energy. Mr. Kelly said that in retail open access markets, NIPSCO would not be involved at that level in those types of transactions but instead, NIPSCO would simply be wheeling the power and much of the activity would occur between the customer and third parties under MISO's tariff rather than with NIPSCO's involvement under NIPSCO's retail tariff. Said differently, NIPSCO is, by design, too involved in facilitating Tiers 2 and 3 (in addition

to the basic bundled firm service of Tier 1) to consider Rate 831 as retail wheeling or retail open access. Finally, he stated that if this was akin to deregulated retail wheeling, NIPSCO would remain the provider of last resort, which is not the case with Rate 831. He explained that Rate 831 requires a five-year notice for a customer to increase its Tier 1 firm contract amount, which protects NIPSCO's other customers from industrial customers "swinging" on its system.

Mr. Kelly testified Rate 831 is designed at parity in the ACOSS and is therefore not being proposed as a discounted service. Further, the identified cost shift to other customer classes for the reduced firm requirements of Rate 831 customers is just and reasonable because Rate 831 is not being subsidized by other classes since the rate is designed at parity. Finally, because the rate is fully costed, no "exit fee" should be assessed against the class to pay for "legacy costs" of the system as suggested by Dr. Boerger and Mr. Wallach. He explained that while the anticipated 184.556 MW of firm demand in Tier 1 (for the "original" five customers measured at the customers' meters) is lower than the amount of firm demand for which these customers have contracted with NIPSCO historically, the rate proposed for that 184.556 MW is at full cost without a discount. He said that still holds true now that an additional customer has been added to the proposed design after expressing interest in joining the rate rather than the originally proposed Rate 830. Mr. Kelly testified the transmission service is also not discounted under Rate 831. He stated that Rate 831 includes a fully costed charge for typical retail transmission service. He explained that for customers that have generating facilities (i.e., QFs) adjacent to their industrial premise, Rate 831 allows any outflows from the generator to be utilized at the industrial premise at a discounted charge for using NIPSCO's transmission system, but all other usage of NIPSCO's transmission system by those same qualifying customers and other Rate 831 customers will be charged at the fully costed transmission rate. Further, the discounted charge is only anticipated to apply to two of the six customers that would take retail service under the rate.

In response to the various challenges to Rate 831 proposing that Rate 831 should only be approved if something akin to an "exit fee" is charged to the participating customers, he understood the rationale offered in many of the arguments that NIPSCO's generation fleet was built to serve all customers including these Rate 831 customers. He stated, however, that these arguments are misplaced for three reasons. First, the idea of an exit fee borrows from policies in other states that have deregulated the generation function from traditional vertically integrated structures. He explained that in those states, the benefit of the bargain was that customers could enjoy the risks and opportunities of retail open access in exchange for buying their way out of the stranded costs of the utility that they would be leaving behind. He explained that the scenario NIPSCO and its other customers are facing is very different because here, large, globally competitive industrial customers with the financial and operational capability of building and operating their own internal generation are pursuing additional cogeneration solutions to avoid NIPSCO's vertically integrated cost to serve. When other states were deregulating, those customers seeking retail open access were not constructing their own cogeneration but were instead seeking access to other third-party generation capacity that already existed in the marketplace. Second, an exit fee would further exacerbate the situation that led NIPSCO to propose Rate 831 in the first place – NIPSCO's cost to serve exceeds these customers' cost to construct and own additional cogeneration facilities or otherwise significantly reduce their loads. Mr. Kelly testified that NIPSCO's proposed Rate 831 structure is a balanced proposal that seeks to preserve some fixed cost contribution from these largest industrial customers into the future. However, to the extent that these customers are faced with an exit fee that would completely offset (or worse) any savings they might achieve in the

MISO markets under Tiers 2 and 3, NIPSCO fully expects that they will continue to rationalize their internal loads with self-funded incremental generation capacity and other measures. He indicated that in that circumstance, the effort to charge a $40 million exit fee is going to lead to stranding the fixed costs associated with the 184.556 MW of firm service these customers would have otherwise paid under the Rate 831 proposal resulting in shifting even more costs to those classes in the long run as NIPSCO's largest industrial customers leave the system. Third, the industrial customers have already abandoned fully firm service from NIPSCO's generation resources years ago. Mr. Kelly noted that in the 1980s, the Commission recognized that it was appropriate for these industrial customers to receive something less than firm service from NIPSCO in exchange for a reduced rate. Because of that interruptible level of service, they have not been responsible for much of the need for additional generation for more than two decades. Mr. Kelly stated that for these reasons, proposals for an exit fee on Rate 831 should be rejected. He testified that if Rate 831 were approved but included a cost of service allocation that increased the fixed cost allocation (i.e., an exit fee), NIPSCO would need to withdraw its ARP proposal rather than implement the rate, and NIPSCO would propose a 90-day procedural schedule to address any rate structure alternatives for its large industrial customers currently served under Rates 732, 733, and 734 and the effects of those alternatives on the other issues in this case.

Mr. Kelly disagreed with Mr. Lahtinen's proposal for addressing the Phase 2 True Up by requiring a minimum of 30,000 kW of Tier 1 service under Rate 831 except in circumstances when a customer's historical firm amount was less than 30,000 kW. Instead, NIPSCO proposed that if the five largest industrial customers are unable or unwilling to subscribe to the 184,556 kW in total under the proposed design, a 90-day procedural schedule be established to address the proper allocation of the 184,556 kW among the five largest customers or any rate structure alternatives that parties may offer for its large industrial customers currently served under Rates 732, 733, and 734. He indicated that to the extent other classes outside of Rate 831 are affected, NIPSCO's pro forma revenue requirement and ACOSS may also need to be revisited.

Mr. Kelly testified that NIPSCO only had four other qualifying customers under Rates 732 and 733 and had assumed that none of those customers would take service under Rate 831 because their firm load was not significantly higher than ten MW. However, now one of the four remaining qualifying customers intends to take service under Rate 831. He explained that NIPSCO's testimony was written to isolate the Phase 2 True Up to specifically manage the uncertainty of the subscription for NIPSCO's five largest customers. He said that in order to avoid an insurmountable level of cost shift to other classes, the industrial service structure was proposed at that 184,556 kW of Tier 1 service for those five largest customers. Mr. Kelly testified that although another customer has expressed intent to participate in Rate 831, the incremental impact between its participation in Rate 831 versus the prior Rate 830 is minimal in the final proposed design of Rate 831 because most of the load that would be available to participate in the non-firm Tiers 2 or 3 is minimal and is partially served on NIPSCO's interruptible (and curtailable) Rider 775 today. He testified that based on the revised Phase 2 True Up proposed here, this sixth customer is likely to sign up for the minimum 10,000 kW of Tier 1 firm service which would be very close to the customer's historical level of firm service.

Mr. Kelly agreed with US Steel witness Thornton that additional information regarding the contractual requirements of Rate 831 would be helpful to customers and third parties seeking the ability to transact under Rate 831. He noted that Mr. Westerhausen is sponsoring a contract that

can be used between NIPSCO and Rate 831 customers, and Mr. Campbell is providing additional detail on the required terms of the multiple-party contract among NIPSCO, its Rate 831 customer, and a third-party capacity or energy supplier. Mr. Kelly disagreed with Mr. Thornton's assessment that additional time will be needed for customers to implement Rate 831 assuming an order is received by the end of August 2019. He stated that NIPSCO is proposing that any qualifying customer that is unable to take service under Rate 831 be placed on either proposed Rate 832 or 833 as a temporary "sub"-rate within Rate 831 with the requirement that the customer also maintain any historical curtailable service (MISO LMR registration) under prior Rider 775 through the end of the current MISO 2019/2020 Planning Year. He explained that NIPSCO is not proposing that Rider 775 or its monthly bill credit would continue as a service structure once the 800 series rates go into effect, but any customer unable to take service under Rate 831's Tiers 1, 2, and/or 3 that also had a Rider 775 LMR registration be required to maintain it through the current 2019/2020 MISO Planning Year. He said that while the customers will be required to subscribe to their portion of Tier 1 service in the Phase 2 True Up once the rate takes effect, this approach will provide the necessary bridge for any customer that is not able take service immediately under Tiers 1, 2, and or 3 of Rate 831. Mr. Kelly testified NIPSCO has identified a process for assisting customers in addressing their MISO LMR exposure when activating their Rate 831 service. He explained that after discussions with customers, NIPSCO is proposing that customers be able to purchase any MISO Zone 6 ZRCs associated with the customer's existing firm load that is transferring to Rate 831 above their Tier 1 firm election. Further, to assist customers with procuring additional ZRCs from third-party suppliers during the 2019/2020 planning year, NIPSCO is also offering to conduct a RFP in the coming months for the benefit of its Rate 831 customers, allowing them as many tools as possible in firming up their LMR obligations should they so desire when activating their Rate 831 service. NIPSCO believes this approach will address the concerns raised by Mr. Thornton.

Mr. Kelly agreed with Mr. Thornton that additional information would help clarify how proposed Rate 831 will be implemented. He stated that after discussions with customers expected to take service under proposed Rate 831, NIPSCO is proposing that the five-year contract requirement be adjusted so that it can synchronize with the completion of the last MISO capacity planning year that would be in effect. He indicated that failing to align the contract terms with the closure of the planning year could result in a scenario where a customer's firm and non-firm capacity requirements are changing intra-year without the ability to address that change easily and seamlessly through the annual auction process. Therefore, NIPSCO is proposing that the contract would expire the later of five years from the contract's signing date or the completion date of the last MISO Planning Year in effect during the five years that the contract would otherwise cover.

Mr. Kelly testified that to clarify confusion with curtailment of LMRs under Rate 831 and interaction with Rider 876, LMRs under Rate 831 Tiers 2 and 3 will be registered along with a firm service level including both Tier 1 and any additional capacity procured for Tiers 2 and 3. This firm service level will set a clear floor that customers curtail to in the event MISO exercises the curtailment of the entire LMR capacity registered. He explained that like today under Rider 776, additional services granted under Rider 876 for back-up and maintenance service will not alter this firm service level. As such, NIPSCO proposed language to clarify that service under Rider 876 cannot be used to nullify some or all of a MISO LMR obligation to curtail. Mr. Kelly noted that in instances where MISO does not ask for the entire LMR capacity, customers will only need to drop the requested relief sought by MISO. He clarified that in instances where a customer

can be entirely firm under Rate 831 and is taking service under Rider 876, during times of curtailment, Rider 876 is subject to curtailment when curtailments under Rate 831 are insufficient.

Mr. Kelly testified that if the Commission does not approve the proposed industrial service structure or makes material modifications to which NIPSCO does not agree, NIPSCO is proposing that a 90-day procedural schedule be established to address any alternatives that parties may offer for its large industrial customers currently served under Rates 732, 733, and 734 and the effects of those alternatives on this case's other issues. He explained that Rate 831 directly affects the revenue requirement, specifically the fuel and related expenses. Accordingly, if NIPSCO doesn't have a final determination on the rate structure for these large industrial customers, then NIPSCO doesn't have a final revenue requirement or ACOSS and cannot implement new rates for any customer class.

C. Ms. Shikany. Ms. Shikany addressed various revenue requirement issues and pro forma adjustments raised by the parties, discussed normal retirement accounting, provided actual utility plant in service, associated depreciation, and capital structure at December 31, 2018 (removing two TDSIC projects from the Seven-Year Electric TDSIC Plan Regulatory Asset included in rate base in RB 11-R and AMTZ 5-R), provided updated projections for utility plant in service, associated depreciation, and capital structure at June 30, 2019, and December 31, 2019 (based on actual amounts recorded through December 31, 2018, with the addition of forecasted 2019 activity obtained from or based upon assumptions in NIPSCO's 2018 AFP, and updated Electric Rate Case Amortization Expense based on the most current rate case expense estimates), and presented revised schedules supporting NIPSCO's revenue requirements reflecting its rebuttal positions, including: (1) Operating Revenues / Fuel & Purchased Power to (a) eliminate an inconsistency between Mr. Chriss' analysis of load profile and that utilized in NIPSCO's COSS and (b) to reflect an additional migration for one large industrial customer from current Rate 730 to Rate 831; (2) Rate Base, Depreciation Expense, and Amortization Expense to reflect rate base amounts concurrent with current projections of utility plant in service at both June 30, 2019, and December 31, 2019, updating the accumulated depreciation, depreciation expense, and amortization expense associated with these amounts, and updating electric rate case amortization expense based on the most current rate case expense estimates; and (3) WACC to reflect capital structures concurrent with current projections at both June 30, 2019, and December 31, 2019.

Ms. Shikany disagreed with Mr. Eckert's proposal that Uncollectible Expense be based on a two-year average because he removed 2015 in NIPSCO's proposed three-year (2015-2017) average because he believes 2015 was significantly higher than 2016 and 2017. She explained the write off as a percentage of revenues was 0.59% in 2015, 0.31% in 2016, and 0.35% in 2017 and noted that write-offs as a percentage of revenues ranges from 0.31% to 1.08% during the last ten years (2008-2017) with two years in which write-offs as a percentage of revenues exceeded that in 2015. She testified the OUCC's calculation is not reasonable because it produces the lowest level of write-offs as a percentage of revenues in each of the ten scenarios.

Ms. Shikany disagreed with Mr. Eckert's proposed reduction to Vegetation Management Expense based on a five-year historical average budget growth rate. She explained that NIPSCO's proposed rates are based on a forward-looking test year (January 1, 2019 – December 31, 2019) and that NIPSCO's 2018 AFP is the underlying basis for its rate request, which is consistent with Ind. Code § 8-1-2-42.7. She testified that unlike Mr. Eckert's calculation based on rolling forward

the 2018 budget amount by the average five-year (2014 – 2018) historical growth in budget, the amount that NIPSCO included is projected data for the forward-looking test year, which is consistent with NIPSCO's budget methodology and based on price times a quantity calculation.

Ms. Shikany disagreed with Mr. Eckert's proposed decrease in depreciation expense because NIPSCO was unable to validate the mathematical accuracy of his proposed adjustment. She testified that NIPSCO's proposed level of depreciation expense was calculated by multiplying NIPSCO's forecasted original cost of utility plant in service by the proposed depreciation accrual rates. She noted that Mr. Eckert did not oppose NIPSCO's proposed rate base but that when NIPSCO multiplied its projected original cost rate base by the OUCC's proposed depreciation accrual rates, it could not reproduce the OUCC's calculation.

Ms. Shikany disagreed with Mr. Lahtinen's characterization of early accelerated recovery. She testified that NIPSCO has not proposed to "accelerate" depreciation but instead conducted a depreciation study and presented depreciation rates that match the expected life of the units – that is not "acceleration" but simply the proper function of depreciation. She described that NIPSCO has offered to defer the recovery over a longer period of time than the units' estimated useful lives. She explained that depreciation studies are prospective and any future accruals of the depreciable property should be amortized over the remaining service life of the property. She stated that when NIPSCO made capital investments that increased the average service lives of certain electric plant accounts, thereby extending the return of its capital investments, no parties objected.

In response to Mr. Gorman's proposal that ECRM Tracker Deferred Expenses be amortized over four years instead of two years as proposed by NIPSCO, and his concern that if NIPSCO amortizes over a two-year period but the base rates remain in effect for four years, then NIPSCO will recover more than double the estimated ECRM deferred costs, Ms. Shikany explained that NIPSCO proposed to amortize these amounts over a two-year period, which is the approximate length of time it would take to recover these costs through the currently approved ECRM Tracker. She stated that consistent with past practice and as recommended by Mr. Eckert in this proceeding, NIPSCO would make a compliance filing to reduce base rates when the amortization of each regulatory asset is complete, which eliminates this risk.

Ms. Shikany disagreed with Mr. Blakley's proposed decrease in income tax expense due to a five-year amortization period for unprotected excess ADIT. She indicated that if Mr. Blakley's proposal is accepted, NIPSCO should be authorized to make a compliance filing at the end of the amortization period to increase its rates accordingly. In response to Mr. Eckert's proposal for a different adjustment to synchronized interest expense, she explained that synchronized interest expense is calculated by multiplying rate base by the cost of long-term debt. As noted by OUCC witness Eckert, the OUCC did not oppose NIPSCO's proposed rate base or cost of debt. She stated that the difference in NIPSCO's and the OUCC's calculation appears to be due to rounding.

Ms. Shikany explained NIPSCO's basis of accounting required by the Commission, including the level of detail the Uniform System of Accounts requires of NIPSCO to maintain its plant records, guidance on the level of detail required when recording additions and retirements, and guidance on how to account for retirements. She testified that in accordance with Uniform System of Accounts guidance, NIPSCO credited Utility Plant in Service and debited Account 108, Accumulated Provision for Depreciation of Electric Utility Plant in amounts equal to the original

cost of the asset, which results in no change in the net book value of rate base. She stated that this resulted in a debit balance in accumulated depreciation of $102,923,994 and $142,329,364, for Unit 7 and 8 respectively, which represents the estimated remaining net book value at the date of the physical retirement. Ms. Shikany noted that the Uniform System of Accounts does not offer any alternatives to this methodology. She stated that the Uniform System of Accounts provides further instructions on Depreciation Accounting and that NIPSCO utilized the composite method referenced in those instructions. She testified that consistent with past requests and Commission rulings, NIPSCO is seeking approval of depreciation rates on a FERC account-by-account basis, not by a FERC account-by-account-by-generating station basis.

Ms. Shikany stated that an extraordinary retirement occurs only if the Commission, by order, directs that upon retirement the remaining net book value be recorded as a regulatory asset. She explained that NIPSCO is seeking Commission approval to treat the retirements of Schahfer and Michigan City generating stations as extraordinary and that NIPSCO is seeking approval well in advance of these retirements to: (1) establish a regulatory asset in an amount equal to the remaining future accruals at the date of retirement; (2) defer regulatory recovery of these amounts through 2030; and (3) include this regulatory asset in NIPSCO's calculation of rate base in subsequent base rate proceedings.

D. Mr. Scott. Mr. Scott responded to opposition to the pro forma labor and benefits that NIPSCO presented in its case-in-chief by Mr. Eckert and Mr. Gorman. He noted that in the event that vacancies are not filled, or these vacancies are filled, but other vacancies arise, there will not necessarily be a corresponding decrease in labor cost because the work must still be done and is often filled by overtime or outside contractors.

In response to the proposed adjustment to benefits expense, Mr. Scott testified that NIPSCO's budget in actuality understates the total benefits expense. He stated that in theory, NIPSCO should have built the budget based upon a benefits-per-employee calculation, but instead, it is based upon the actual headcount as reported in the actuarial reports. As such, adjusting labor benefits for vacancies has already been factored into the budget numbers.

E. Mr. Augustine. Mr. Augustine addressed the perceived issues with NIPSCO's 2018 IRP raised by Mr. Griffey, Ms. Medine, and Mr. Nasi. In response to Ms. Medine's claim that the IRP has not been approved and thus cannot be used to support elements associated with this rate case, he stated that the IRP is a planning document and is not subject to a ruling or formal approval by the Commission. He testified that as part of its transparent IRP process, NIPSCO conducted six public advisory meetings over the course of 2018, along with many other individual meetings with stakeholders to provide information and receive feedback on the methodologies and assumptions used in the IRP. He noted that as part of this process, NIPSCO performed several stakeholder-requested analyses prior to submission of the IRP, including some requested by Ms. Medine and the ICC.

Mr. Augustine summarized the general process NIPSCO undertook to evaluate retirement and replacement decisions in its IRP. In response to Ms. Medine's suggestion that NIPSCO should have performed a single optimization analysis to identify the preferred retirement plan for the coal units, Mr. Augustine testified that if NIPSCO would have performed a single, least cost

optimization analysis, the IRP models would have determined that the optimal portfolio would be to retire all coal units as soon as possible.

In response to Mr. Griffey's claims that NIPSCO only applied flexibility to its future selection of resources after making an inflexible choice on early plant retirement dates, Mr. Augustine testified that NIPSCO actually concluded that retiring coal earlier than the dates outlined in the preferred portfolio would be the least cost portfolio outcome. He explained that NIPSCO found that retirement of units at Schahfer as early as 2021 would provide savings for customers, but concluded that early retirement was not executable by 2021, given the required transmission upgrades that must be made to ensure system reliability. He also explained that NIPSCO found that retiring Michigan City in 2023 provided the greatest cost savings to customers, but concluded that a change of over 75% of NIPSCO's physical generation at one time in 2023 would create potential reliability and execution risk for customers. Thus, NIPSCO concluded that a 2028 retirement date for Michigan City would allow for a more orderly portfolio transition and provide an ability to gain access to better information regarding technology change and future customer demand. He stated that if NIPSCO had not applied flexibility in its retirement decision, the preferred portfolio would have called for retirement of the units as early as possible.

In response to Mr. Griffey's criticism of the number of scenario/portfolio combinations that were evaluated and his statement that NIPSCO should have constructed evaluations of different retirement dates that changed by scenario, Mr. Augustine testified that NIPSCO's analysis evaluated a very broad range of retirement dates across a range of scenarios and stochastics. He explained that the primary point of evaluating eight different retirement date combinations for the coal fleet across all scenarios and stochastics was to provide a highly transparent analysis of different retirement strategies against different potential market outcomes. He stated that instead of limiting the evaluation of flexibility, as Mr. Griffey suggests, this approach actually allowed NIPSCO to evaluate the performance of different portfolios against changing market assumptions over time.

Mr. Augustine disagreed with Mr. Griffey's claim that by using a two-step approach and never comparing the results across steps, NIPSCO arrives at an inappropriate conclusion in its IRP. Mr. Augustine noted that Mr. Griffey's claim fails to acknowledge the rationale behind the two-step process and the multiple objectives NIPSCO evaluated in its review of retirements and replacement options. He testified that NIPSCO performed retirement analysis in multiple phases against different resource alternatives and concluded that early retirement of coal units was cost effective for customers. He explained that NIPSCO then performed a replacement analysis to evaluate the replacement alternatives through a more comprehensive set of parameters and scoring mechanisms, including a portfolio diversity component to test natural gas and renewable replacements and a commitment duration component, where a mix of PPA and ownership options were evaluated. He testified that resource planning decisions were made based on an integrated scorecard approach and not purely on least cost, which is why certain retirement dates are staggered and why a mix of replacement alternatives was proposed in the preferred portfolio.

Mr. Augustine testified that Mr. Griffey's comparison to show that an alternative retirement plan would have been more cost effective than NIPSCO's preferred portfolio is an apples-to-oranges comparison and ignores the other objectives evaluated by NIPSCO in the replacement analysis. He explained that NIPSCO found that a wide range of resource alternatives

were lower cost than operating and maintaining the existing coal fleet. He concluded that Mr. Griffey did not conduct any dispatch or portfolio analysis that would demonstrate a different outcome under his proposed alternative approach.

In response to Ms. Medine's contention that NIPSCO did not properly account for recent changes in delivered coal price expectations for 2019 in the IRP and that NIPSCO did not fully consider all realistic commodity price combinations, Mr. Augustine stated that the difference in assumed coal price raised by Ms. Medine for the fleet averages about $0.13/MMBtu, which represents around a little more than $1/MWh, less than 5% of the total variable costs for the units, which is not a significant difference in the context of other drivers of the IRP analysis, including natural gas prices, which dropped even further since the development of the IRP assumptions. He also stated that NIPSCO's 2018 IRP assessed portfolio performance across a wide range of coal and natural gas prices precisely because future market conditions are uncertain and will inevitably be different than any single point forecast. In response to Ms. Medine's critique that NIPSCO did not appropriately consider a scenario without a carbon price and with high gas prices, Mr. Augustine testified that as part of its 2018 IRP stakeholder process, NIPSCO evaluated a scenario developed by the ICC and Ms. Medine that had the same assumptions she claims NIPSCO ignored. He stated that this scenario had no CO2 price, flat coal prices, and high natural gas prices. He noted that the results from this scenario were consistent with the other four scenarios, concluding that retiring coal capacity early provided substantial cost savings to customers.

Regarding Mr. Griffey's assertion that NIPSCO did not properly account for expected solar cost declines over the long term, Mr. Augustine testified that as Mr. Griffey recommended, NIPSCO directly calibrated its generic solar cost projections to results from the RFP and assumed a $1,006/kW (real 2017$) cost for 2023 additions, which is a cost *lower* than Mr. Griffey's recommendation. Mr. Augustine further explained that Mr. Griffey's claim that inaccurate solar cost assumptions were used in the IRP analysis was false due to his failure to account for ongoing coal maintenance capital expenditures, accelerated tax depreciation benefits for solar, and differences in generic solar additions in his calculations.

In response to Mr. Griffey's belief that NIPSCO underestimated the capacity value associated with wind resources, Mr. Augustine noted that historical data for wind plants operating in Indiana is not a reasonable way to project future capacity credit values for new assets. Regarding Mr. Griffey's belief that NIPSCO underestimated the potential of future wind output degradation, Mr. Augustine testified that ongoing maintenance will limit the amount of degradation seen at the future wind facilities and that the IRP analysis included these costs. He explained that while solar bidders to the RFP provided specific information regarding degradation curves, wind bidders did not offer such information, so NIPSCO did not include any assumptions for this factor in the IRP analysis. He noted that Mr. Griffey did not attempt to quantify the potential impact of any degradation, nor did he present any data regarding wind degradation that would suggest he has better information than the RFP bidders, all experienced wind developers. Furthermore, Mr. Augustine noted that NIPSCO does not view this factor as having a meaningful impact on cost outcomes, especially given the large cost savings associated with wind additions to the portfolio.

In response to Mr. Griffey's concerns with the maintenance capital expenditure projections used in the 2018 IRP, Mr. Augustine testified that NIPSCO's capital expenditure projections are consistent with expectations of future operations. He explained that retiring a plant early reduces

the expected maintenance capital that is required, due to a reduced need to continue investing in the asset for long-term use, which is an important reality that must be incorporated in an IRP analysis. He stated that Mr. Griffey neglects this reality and seems to think that maintenance capital plans should be the same regardless of when a plant is expected to retire. He said that Mr. Griffey's proposed approach ignores significant cost savings that are associated with retirements.

Regarding cost assumptions relating to ELG and CCR compliance and treatment of potential CO2 costs, Mr. Augustine testified that NIPSCO evaluated different means of ELG compliance and conservatively developed its final set of portfolios around the assumption that plants could achieve compliance through a non-ZLD approach. He noted that NIPSCO evaluated a retirement portfolio that extended the retirement date of Schahfer Units 14 and 15 to 2028 under the assumption that ELG compliance could be achieved through a retirement in that year as opposed to a specific control mechanism by an earlier date. He stated that although NIPSCO's four *scenarios* do not envision compliance obligation changes associated with ELG and CCR Rules, NIPSCO evaluated potential changes in compliance obligations in the *portfolio* development process. He noted that in its 2018 IRP stakeholder process, NIPSCO performed an analysis of the coal retirement economics requested by Ms. Medine and the ICC with *no* new environmental capital incurred at the coal plants – effectively a scenario where no environmental compliance is required over the entire planning period – in which NIPSCO found that retiring coal early still provided significant savings to customers. With regard to treatment of potential CO2 costs, Mr. Augustine stated that NIPSCO evaluated a range of potential CO2 price futures, including a customized scenario requested by the ICC. He explained that while the two CO2 price trajectories developed in the 2018 IRP include a CO2 price starting in 2026, NIPSCO also analyzed scenarios without any CO2 price for the *entire* IRP forecast horizon. He testified that the results of this scenario concluded that retiring coal capacity early would lead to significant savings for customers and that NIPSCO also performed an analysis of the coal retirement economics requested by the ICC with no CO2 price, high natural gas prices, flat coal prices, and no incremental capital, and still found that retiring coal early provided significant savings to customers.

Mr. Augustine responded to general concerns regarding NIPSCO's IRP analysis identified by Mr. Griffey and Ms. Medine, including concerns regarding NIPSCO's incorporation of potential congestion risk, ancillary services costs, and the new proposed industrial rate structure; a claim that NIPSCO has not performed its revenue requirement calculation properly; and a claim that certain retirement portfolios cannot be properly compared due to inconsistent assumptions. He stated that NIPSCO acknowledged the existence of congestion and nodal price risk for certain resources in its 2018 IRP and noted that this would be evaluated in further resource selection processes associated with the RFP, as was done in NIPSCO's analysis for its recently pursued wind resource additions. He stated that while it is possible that MISO-wide ancillary services costs will increase in the future, Mr. Griffey did not provide any actual evidence or analysis to support his implication that NIPSCO's preferred portfolio would face higher net costs than a portfolio that retains coal. With regard to future industrial load uncertainty, Mr. Augustine testified that NIPSCO did evaluate a low-load scenario, which was based on substantial industrial load leaving the system. He noted that although it was combined with other factors that differed from the Base Case and although it was not based on specific assumptions regarding lower industrial firm demand that may materialize from a new rate structure, it found that retiring coal units provided savings to customers. He stated that any loss of firm load can be managed through NIPSCO's procurement

of replacement resources, while investing in and maintaining the high-cost coal units could result in more high-cost capacity than necessary if load obligations were to fall significantly.

Mr. Augustine testified that Ms. Medine's statement that NIPSCO's NPV approach assumes levelized recovery of capital investment is a false assertion. He explained that Ms. Medine's claim shows a lack of understanding of how NIPSCO conducted its IRP analysis, since NIPSCO did not levelize capital expenditures but instead performed a revenue requirement calculation that puts new capital into rate base as units enter into servicing, resulting in NIPSCO earning a return of and on that new capital over time. As a result, the recovery of new capital is front-loaded in NIPSCO's analysis, meaning that customers pay more in the first year than in subsequent years, contrary to Ms. Medine's claims. In response to Mr. Griffey's suggestion that he was unable to compare the economics of retiring Schahfer Units 17 and 18 versus the alternatives because the portfolio that holds all coal through end-of-life does not include new DSM and EE measures beyond what is currently in NIPSCO's approved plans, Mr. Augustine testified that the purpose of the IRP is to compare current resources with alternatives, whether they be demand- or supply-side options, as NIPSCO has done. He explained that in evaluating different portfolio options within similar reserve margin constraints, alternatives such as DSM and other supply-side resources are only needed when coal units retire.

Mr. Augustine concluded that while the 2018 IRP involved a complex set of portfolio analyses, including hourly dispatch analysis and detailed revenue requirement projections, the simplest explanation for NIPSCO's preferred portfolio is that the *all-in* costs of acquiring and operating new renewable resources are far lower than the expected costs of continuing to maintain and operate NIPSCO's coal units. He testified that in the IRP, the all-in costs for PPA or NIPSCO-owned renewables over their expected operating horizons ranged between approximately $25/MWh and $51/MWh (nominal $) and that over the same period, the *variable-only* costs for the coal fleet associated with coal expenses and variable operations and maintenance costs are close to or even higher than the *all-in* costs of many of the renewables options. Therefore, any additional costs for the coal plants associated with fixed operations and maintenance activities, new capital investments, or future carbon regulations all raise the costs substantially higher than new renewables. He stated that even in scenarios where these other costs are eliminated or dramatically reduced, retiring the coal plants and replacing the energy and capacity with renewables is a lower cost outcome.

F. Mr. Hooper. Mr. Hooper responded to the OUCC's proposal to limit the adjustment of Forward Test Year Vegetation Management expense to a five-year average value. He testified that NIPSCO's clearance distances are designed to provide adequate clearance at time of trimming to allow for vegetation growth with minimal impact to system reliability until the next trim cycle. He explained that while Mr. Eckert's analysis is mathematically correct, it fails to consider the benefits of maintaining a 1,500 mile clearance goal and fails to account for the fact that the costs of vegetation management continue to climb. He noted that the OUCC did not challenge the underlying facts supporting the rationale for the proposed increase in Vegetation Management expense and contended that reducing the requested amount by $1.3 million would not be representative of the ongoing cost of those activities.

G. Mr. Carmichael. Mr. Carmichael responded to criticisms from Mr. Nasi that regulatory timelines NIPSCO assumed for compliance with the EPA's CCR and ELG Rules were

too short because of available extension options and EPA's plans to reform those rules and that assumed capital and O&M expenditures were too high or not properly supported. Mr. Carmichael explained the overall process NIPSCO utilized to determine the anticipated compliance timelines and environmental cost estimates that were utilized in NIPSCO's 2018 IRP, including how NIPSCO determined compliance timelines based on a plain reading of the rules and regulatory agency guidance and how available extensions were considered and applied. He discussed how NIPSCO utilized expert third-party consultants with extensive industry experience, internal expertise, and available industry data to determine the capital environmental cost estimates used in the IRP and reviewed the potential options for meeting compliance these experts provided to assist in selecting technical solutions/projects. NIPSCO also balanced current and future compliance obligations with operational needs and overall cost to choose a compliance option; the estimates were then adjusted to align with the estimated annual spend to complete a project; and dollars were applied to the estimates for owner's costs, indirect costs, and escalation. In each instance, NIPSCO utilized the most reasonable compliance alternative and estimated cost and used its best judgment. However, Mr. Carmichael noted that, when predicting the future state of environmental regulatory compliance, there will necessarily be some uncertainty.

Mr. Carmichael also explained why it is important for NIPSCO to include its best estimate for environmental compliance costs in its long-term planning, including in its 2018 IRP. While there is uncertainty around practically all major environmental rules, he stated that NIPSCO must make judgments about many things, including environmental rules, when making important decisions like what generation will best position NIPSCO to serve its customers in the future. NIPSCO also cannot assume no compliance costs for a rule that is subject to challenge or reconsideration. He noted that Mr. Nasi criticized NIPSCO's environmental compliance cost estimates used for the 2018 IRP but nowhere provided his own cost estimates. Because NIPSCO conducted detailed cost estimation using proven methodologies and in coordination with its expert consultants, Mr. Carmichael stated that Mr. Nasi's criticisms are unwarranted.

With respect to compliance with the ELG Rule, Mr. Carmichael summarized Mr. Nasi's criticism that NIPSCO has overstated the compliance costs. Mr. Carmichael reviewed the current status of the ELG Rule and noted that NIPSCO incorporated lower ELG costs and adjusted timing assumptions in the 2018 IRP as a result of EPA's yet-to-be-finalized reconsideration of the ELG Rule. He explained that Michigan City Unit 12 is already compliant with the ELG Rule and why the "Postponement Rule" discussed by Mr. Nasi has no bearing on the NIPSCO ELG compliance timing for the Schahfer Generating Station assumed in the IRP for 2023. He also testified that there is no indication the ELG Rule and related requirements will go away completely and how NIPSCO changed assumptions in the 2018 IRP to: (1) lower ELG costs with the assumption that EPA would relax the 2023 ZLD requirement; and (2) assume that a non-ZLD option would be allowed at Schahfer for FGD wastewater. For bottom ash transport water, Mr. Carmichael explained that Schahfer Units 14 and 15 are already retrofitted for compliance with the CCR Rule; thus, there are no additional cost or timing issues related to ELG. Regarding Schahfer Units 17 and 18 bottom ash transport water, he explained that it would be likely that bottom ash transport projects (like those for Units 14 and 15) would be required and that NIPSCO's assumed cost estimates were similar to those projects it has already installed at Units 14 and 15. He clarified that the settlement in Cause No. 44872, which addressed CCR compliance projects but not ELG compliance projects, does not in any way invalidate cost estimates or timing assumptions in the 2018 IRP, nor does it demonstrate that NIPSCO will not be required to comply with the ELG Rule in the future.

Regarding the CCR Rule, Mr. Carmichael noted Mr. Nasi's criticism of NIPSCO's cost estimates. Mr. Carmichael explained that NIPSCO considered all options available under the CCR Rule regarding compliance timelines and costs. He stated that NIPSCO must make decisions and implement compliance plans to meet currently existing requirements even though the rule is undergoing reconsideration. If NIPSCO did not do this and instead waited for a final EPA decision, generating facilities may be forced to shut down early (October 2020 or earlier) to avoid non-compliance with the regulations. Mr. Carmichael testified that this risky approach would be inconsistent with NIPSCO's commitment to provide reliable service to its customers. He also testified about the CCR compliance options that were prepared by third-party consultants and those agreed to in the 44872 Settlement, which have been executed on budget by NIPSCO. He stated that this demonstrates NIPSCO's cost estimates for Schahfer Units 14, 15, 17, and 18 and Michigan City Unit 12 are reasonable. Mr. Carmichael also clarified that his discussion of certain CCR ARO costs, which NIPSCO is not seeking to recover here, was not related to the 2018 IRP. Based on a recent court decision, he also stated that NIPSCO disagrees with Mr. Nasi and does not anticipate that CCR Surface Impoundments will be allowed to continue to receive CCR and non-CCR wastewater in the future.

Mr. Carmichael next addressed criticisms about NIPSCO's compliance plan for the MATS Rule. He specifically disagreed with Mr. Nasi's assertion that NIPSCO's inclusion of MATS-related O&M costs in the 2018 IRP was unreasonable. Mr. Carmichael explained that the MATS Rule's requirements are still in effect, and NIPSCO must continue to comply with them. Because the MATS Rule remains effective and it is unlikely that EPA will withdraw MATS entirely or drastically alter the rule, NIPSCO has assumed it will continue to incur compliance costs for the time in which the impacted generating units operate and, thus, made no changes in its MATS compliance plans. He also noted that the majority of the O&M costs to comply with MATS come from operation of the FGD systems; thus, even if EPA were to repeal MATS, the FGDs would be required to continue to operate for purposes of compliance with other EPA rules, and the FGD-related O&M costs would continue to be incurred. More broadly, Mr. Carmichael criticized Mr. Nasi's advocacy for a "wait-and-see approach" to compliance, providing examples of how this previously would have resulted in coal-fired generation that would not have had control equipment installed in time for compliance and thus would have been non-operational for years. This is why it would not be prudent for NIPSCO to utilize this wait-and-see approach and assume that CCR, ELG, MATS, or other EPA rules will result in no future cost.

Regarding NIPSCO's path to compliance with CSAPR, Mr. Carmichael responded to Mr. Nasi's critique that NIPSCO failed to adequately justify the selection of SCR technology over the less expensive SNCR technology. After discussing NIPSCO's response to Peabody Request 1-010, included as Attachment No. MJN-5 to Mr. Nasi's testimony, Mr. Carmichael further explained the operational characteristics of Schahfer Units 17 and 18. He testified that installation of SNCR technology would not reduce NOx emissions below the current allocation. On the other hand, SCR technology can achieve a NOx rate that would bring Schahfer Units 17 and 18 in-line with the current NOx allocation rate. While SCR is a more capital-intensive technology, if the EPA continues the historical trend and lowers the ozone standard below 70 ppb, as expected during the IRP planning horizon, or if additional environmental regulations are promulgated that impact the relevant emission requirements, it is likely that SNCR technology would not be able to achieve compliance without a significant curtailment of coal-fired generation to achieve compliance or significant reliance on allowances in future NOx markets, assuming that the markets exist at a

price that justifies running coal-fired units. He added that if NIPSCO implemented SNCR technology and incurred the associated capital costs and later needed to comply with more stringent standards, SCR technology would likely need to be implemented at a significantly higher cost than implementing SCR technology in the first instance. Mr. Carmichael summarized that without SCR, NIPSCO's operational flexibility—its ability to run Schahfer Units 17 and 18, if at all—would become increasingly constrained as EPA implements the 70 ppb ozone standard and future standards. Regarding "operational flexibility" that SCR technology would allow, he explained that NIPSCO was speaking about the ability to continue to ramp output of the relevant units to meet system needs while also complying with current and future regulations because SCR allows units to operate over a wider range of output at lower emission rates than SNCR allows. Based on the operational characteristics of NIPSCO's generation fleet, existing and expected regulations, and as advised by internal and external subject-matter experts, NIPSCO believes SCR technology is the most appropriate technological assumption for long-term CASPR compliance.

Mr. Carmichael testified that NIPSCO has a proven track record of navigating compliance and assuring that associated timing and costs were ultimately warranted to achieve compliance. With regards to consideration of other scenarios in the 2018 IRP, he also briefly explained that the ICC requested NIPSCO to perform an analysis with its own set of assumptions—scenarios that included no carbon costs, reduced future environmental capital costs, flat coal pricing, and a high natural gas price curve. The output presented at IRP stakeholder meetings showed that, even under the ICC's market scenario with no new environmental capital for the coal plants, retirement of coal as early as possible still remained the lowest cost option. Mr. Carmichael also noted that NIPSCO is required to submit another IRP within the next three years (i.e., prior to the proposed 2023 retirement of the Schahfer coal-fired units) and that this IRP will incorporate the most current information and projections on environmental costs and timing.

Mr. Carmichael also responded to three issues that Mr. Nasi seemed to misunderstand in Mr. Carmichael's direct testimony. First, regarding the alleged mismatch for ELG Rule compliance costs, he clarified that the $170 million estimate from page 13 of his direct testimony is NIPSCO's initial ELG Rule compliance estimate for Schahfer Units 14 and 15. He explained that, looking at page 12 of that testimony, it stated that Michigan City Unit 12 would not need to incur ELG Rule compliance costs, because it has a dry FGD system installed, and this was also addressing Schahfer Units 14 and 15. The $440 million estimate provided in response to discovery, which was included in Nasi's Attachment No. MJN-2, was an estimate for Schahfer Units 14 and 15, as well as Schahfer Units 17 and 18. Second, Mr. Carmichael stated that Mr. Nasi's criticism of NIPSCO not advocating for ELG Rule changes that go beyond bottom ash transport water and FGD wastewater shows that he misunderstands NIPSCO operations and/or the ELG Rule. Mr. Carmichael outlined why it would be nonsensical for NIPSCO to waste time and resources advocating for additional ELG Rule changes when such changes would have no potential benefit for NIPSCO and its customers. Third, regarding Mr. Nasi's criticism of NIPSCO's inclusion and accuracy of capital and O&M costs and inclusion of costs that will be incurred regardless of whether the units continue to operate to justify retirement decisions, Mr. Carmichael pointed to Mr. Augustine's rebuttal testimony, which explained that NIPSCO evaluated a portfolio with no new environmental capital for all coal units and found that retiring coal early provided significant savings to customers even in this scenario.

H. Mr. Campbell. Mr. Campbell responded to Industrial Group witness Dauphinais' testimony about the Rate 831 tariff language regarding curtailment notification and US Steel witness Thornton's testimony related to Rate 831 customer qualification for Auction Revenue Rights ("ARRs")/ Financial Transmission Rights ("FTRs"), recommended phase in period for Rate 831 implementation, and MISO billing disputes.

Mr. Campbell testified that while NIPSCO does not oppose the recommendation by Mr. Dauphinais for a two-hour curtailment notice for Rate 831 customers, consistent with current practices, NIPSCO will add 30 minutes to the LMR notification time to allow for the communication of any MISO curtailment event.

In response to Mr. Thornton, Mr. Campbell testified that Rate 831 customers will not qualify for ARRs/FTRs. He explained that because MISO requires that an entity be registered as a Market Participant to hold FTRs or ARRs, NIPSCO, acting as the MISO Market Participant, will register Rate 831 customers electing Tier 3 service as Asset Owners. He explained that the MISO Tariff and Business Practices Manuals explain what actions Asset Owners are qualified to perform. He stated that MISO Market Participants are the only entities allowed to procure FTRs with MISO because of the additional credit requirements to participate in the FTR market but that MISO Market Participants may act as agents and procure FTRs on behalf of other parties. He stated that under Rate 831, NIPSCO will not act as an agent to procure FTRs on behalf of the Rate 831 Tier 3 Customer but that customers are free to contract with other third-party MISO Market Participants to obtain FTRs. He indicated that any settlements will be handled outside of the MISO settlement process between Rate 831 customers and the third-party MISO Market Participant. He stated that Mr. Thornton characterized allocated ARRs/FTRs as a benefit, but they can also represent a cost and that if Rate 831 customers are allocated ARRs/FTRs, they should also be allocated their portion of any charges associated with the ongoing investment in the transmission system.

Mr. Campbell disagreed with Mr. Thornton's proposal for a phase-in period for Rate 831 implementation. He explained that NIPSCO is proposing that any qualifying customer that is unable to take service under Rate 831 be placed on either proposed Rate 832 or Rate 833 with the requirement that the customer also maintain any historical curtailable service (MISO LMR registration) under prior Rider 775 through the end of the current MISO 2019/2020 Planning Year. He stated that, alternatively, for customers that are intending to take Tier 3 service under Rate 831, customers can choose to take service under Tier 2 until they are ready to transition to Tier 3 service. He noted that this optionality is already present in Rate 831 where customers can change their elections between Tier 2 and Tier 3 quarterly (commensurate with MISO model update cycle).

Mr. Campbell testified that NIPSCO has identified a process for assisting customers in addressing their MISO LMR exposure when activating their Rate 831 service. He explained that NIPSCO is proposing that customers be able to purchase any ZRCs associated with the customer's existing firm load that is transferring to Rate 831 above their Tier 1 firm election to afford customers the benefit of existing firm load that has already cleared the MISO PRA.

In addition, to assist customers with procuring MISO Zone 6 ZRCs from third-party suppliers during the 2019/2020 planning year, NIPSCO is offering to conduct a one-time RFP for intra-year MISO Zone 6 ZRCs prior to the implementation date for the benefit of Rate 831

customers to assist them in firming up their LMR obligations should they so desire when activating their Rate 831 service.

Mr. Campbell disagreed with Mr. Thornton's recommendation that during the proposed phase-in period, NIPSCO should work with its Rate 831 eligible customers to develop a model agreement that includes acceptable terms and conditions for customer-procured capacity and/or energy. He stated there are many ways to construct bilateral arrangements. He noted that an ISDA Master Agreement or EEI Master Contract are industry tools that can help form those agreements, especially in instances where there is a potential for multiple reoccurring transactions. He explained that standalone contracts are also employed, but they can have many of the elements referenced in the ISDA or EEI. He stated that based on NIPSCO's understanding, contracts in the broader market, while similarly structured, have certain provisions that are unique per counterparty requirements and additional provisions that are unique because of customer specific requirements. He indicated that recognizing that there is the potential for standard and non-standard agreements for customer-procured capacity and/or energy, NIPSCO is committed to working with the customer and the customer's identified third party in outlining the terms associated with any potential agreement incidental to Rate 831 service. He stated that in general, such agreements between NIPSCO, customer, and third party for capacity and/or energy will need to be a three-party agreement between NIPSCO, customer, and customer's third-party supplier, and at a minimum such agreement will need to contain provisions that: (1) identify NIPSCO as the Market Participant for the retail customer at MISO; (2) reference-NIPSCO's market based rate authority with FERC; (3) clearly state the Rate 831 customer remains a retail customer of NIPSCO; (4) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations); and (5) incorporates relevant provisions from NIPSCO's Rate 831 schedule.

He testified that NIPSCO also understands that certain terms such as, but not limited to, pricing may need to be treated as confidential and may be limited from view from certain NIPSCO personnel and, further, may be subject to a non-disclosure agreement. He stated that while NIPSCO does not believe a model agreement is necessary or prudent given the unique nature of potential capacity and energy transactions, NIPSCO believes the details outlined above are responsive to the concerns outlined by Mr. Thornton.

Mr. Campbell disagreed with Mr. Thornton's request that NIPSCO modify the language on billing disputes by adding specific dispute resolution provisions, which would define the rights and obligations of NIPSCO and the industrial customer, and include specific remedies. He stated that the dispute process is adequately defined in proposed Rate 831. He described that, in general, the hierarchy as defined within Rate 831 allows an Asset Owner to file the dispute with MISO, while keeping NIPSCO informed. If the dispute is denied and the customer wants to pursue it further, the customer needs to request NIPSCO to file an Alternative Dispute Resolution ("ADR") on its behalf with MISO. He noted that if the customer is unsatisfied with MISO's decision in the ADR, it can pursue a complaint with FERC.

I. Mr. Ranalletta. Mr. Ranalletta disagreed with Mr. Gorman that a contingency factor is not a known and measurable cost and therefore not appropriate for including in rates. He testified that use of a contingency factor in any major construction or demolition

project is well accepted in the industry, the amount selected here is well supported, and it is sufficiently certain for purposes of including expected demolition costs in Mr. Spanos' calculation of depreciation accrual rates. He stated that estimates of demolition costs of NIPSCO's generation plants are prepared with the intent of accurately representing what contractors would bid to abate, remediate, and demolish the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known decommissioning tasks under ideal conditions. He stated that he included a 20% contingency factor in his estimates. He explained that in addition to the known tasks under ideal conditions, contingency is added to account for unknown, but reasonably expected to be incurred, costs. He indicated that the application of contingency is a common and prudent practice in the construction and demolition industries, and it is included in order to recognize the probability of increases in cost due to these unknown events. Finally, he noted that contingency is a cost that is typically included by owners throughout all stages of planning and execution of the project.

J. Mr. Spanos. Mr. Spanos first responded generally to the criticism by other parties regarding the service lives of generating plant. He testified that other parties are misusing the phrase "accelerated depreciation." He explained that NIPSCO's proposed depreciation rates based upon the current estimated useful lives of the generating plants is not a form of accelerated depreciation. He reiterated the service lives used in his study and pointed out that other parties argued not to update the service lives from prior studies or inherent in existing rates or generally not to retire the plants as planned. He testified that in his experience, it is more common for assets such as power plants to be retired before they have been fully depreciated than such assets becoming depreciated before being removed from service. Given this reality, he explained that depreciation rates should be set as accurately as possible but that erring on the higher side for depreciation rates is preferable to erring on the lower side. The likelihood and the risks of adverse effects on both the utility and customers are greater if depreciation is underestimated.

With respect to Mr. Garrett's proposal to reject the Equal Life Group procedure, Mr. Spanos testified that Equal Life Group has been used in Indiana for many years. He quoted the 43526 Order, where the Commission stated, "We consider the debate between [Equal Life Group] and [Average Life Group] to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the [Equal Life Group] procedure." P. 51. He then summarized the history of the use of the Equal Life Group in Indiana.

Mr. Spanos also responded to Mr. Garrett's proposal to remove escalation from decommissioning costs. He again cited to NIPSCO's most recent litigated case and to a 2004 rate case in Cause No. 42359. He testified that in both cases, it was affirmed that decommissioning costs should be escalated to the future time at which the facilities would be retired.

With respect to contingency, Mr. Spanos testified that the use of contingency is also accepted by this Commission and that, indeed, Mr. Gorman's firm had previously proposed to remove contingency for NIPSCO in Cause No. 43526 and was rejected.

Mr. Spanos also responded to the nine mass property accounts for which Mr. Garrett had proposed service life adjustments. Mr. Spanos noted that his depreciation study recommended an increase to the average service life from both current depreciation rates and the estimate from the previous depreciation study. He explained that Mr. Garrett's proposals are to increase the service

lives even further. He testified that Mr. Garrett's adjustments relied too much on mathematical curve fitting and too little on the use of informed judgment. He gave examples where Mr. Garrett's approach resulted in estimated survival years beyond what should be considered reasonable. Finally, he noted that all of Mr. Garrett's adjustments resulted from an error in constructing his charts in Excel, which shifted the smooth survivor curves to the right in each graph.

K. Mr. McCuen. Mr. McCuen responded to the parties' testimony related to excess ADIT. He stated that all witnesses agree that the IRS has mandated that these excess ADIT be passed back to customers using ARAM and that all witnesses understand that the unprotected excess ADIT can be passed back to customers over any reasonable period of time. He testified that he has proposed using ARAM, Mr. Blakley proposed a five-year amortization period, and Mr. Gorman proposed a ten-year amortization period. Mr. McCuen supported his proposal using ARAM based on the Commission's June 1, 1987 Interim Order in Cause No. 38194 and the Report of the Executive Committee filed in that Cause on April 15, 1987, concluding that all excess deferred taxes should be passed back using ARAM, specifically stating that "protected" deferred taxes are those that relate to depreciation method and life of public utility property and the "unprotected" portion includes the remaining balance of excess deferred taxes. The Report found that excess deferred tax reserves existing on the books of utilities at whatever point in time the utility reduces its tax rate in compliance with the Tax Reform Act of 1986, should be returned to the ratepayers utilizing ARAM. Mr. McCuen stated that while the Executive Committee chose not to differentiate, he believes the portion of the unprotected items related to property (repairs, capitalized overheads, and mixed service costs) should appropriately follow the ARAM flow back to customers, and the non-property related excess deferred taxes may have a more appropriate shorter flowback period depending on the underlying cause of the temporary difference giving rise to the deferred tax. Mr. McCuen proposed a ten-year amortization period for these types of items.

Mr. McCuen believes the shorter period offered by Mr. Blakley and Mr. Gorman is not appropriate because: (1) investment decisions have been made taking into account the cash flow for the payment of taxes, whether the payment is to the federal government or a return to the customer, the payments should be made over the same period of time so as not to invalidate the economics underlying those investment decisions which have already been made; (2) the flow-back of excess deferred taxes should be done ratably over the life of the asset giving rise to the deferred taxes to avoid inter-generational inequity between customers today and those customers in the future that will continue to pay for the asset; and (3) a rapid flowback of excess deferred taxes will negatively impact NIPSCO's cost of capital that raises the cost to customers, the WACC will increase at a faster rate with a rapid flowback of the excess ADIT, and the negative cash flow implications for NIPSCO may result in degradation of credit ratings, which will increase financing costs of investments and ultimately the WACC.

Mr. McCuen explained what the pass back would look like had the TCJA not been enacted. He stated that when looking at the unprotected property related items, such as repairs and mixed service deduction, the deferred taxes reverse over the life of the assets as they are depreciated. The assets that these deductions relate to are typically long-lived utility assets with book lives over 40 years. He stated that the deferred taxes are purely the result of timing differences as the tax deduction has been taken more quickly than the expense is incurred for regulatory purposes. He explained that assuming a capital asset was installed at the beginning of Year 1 with a 40-year life but which qualified for the repairs deduction, at the end of Year 1, the entire investment would be

deducted for tax purposes, but for regulatory purposes only one year of depreciation expense would be recorded. He stated that the deferred tax this situation creates will reverse over the remaining 39 years, as depreciation expense is recorded for regulatory purposes. For these reasons, NIPSCO believes amortization of the excess deferred taxes over the remaining life of the assets is the most prudent approach for its customers.

Mr. McCuen testified ARAM provides tax benefits to ratepayers smoothly over the life of the investment. In contrast, flowing it through over a five-year period front loads the benefit. Returning to his example of the single repairs deduction, under Mr. Blakley's proposal, for the next five years rates would be held artificially low as the excess deferred taxes are amortized over his abbreviated timeframe. Then there would be an immediate spike as the abbreviated amortization ends, and the spike would be exacerbated by an increase in the WACC caused by the deferred taxes having been flowed back entirely. He explained using the five-year amortization period means ratepayers will be charged more after that period because the deferred taxes will not be an offset to tax expense and the WACC will be higher. He testified that NIPSCO believes that using ARAM and providing the tax benefits to ratepayers smoothly over the life of the investment is the most prudent alternative.

Mr. McCuen explained how the pass back of excess deferred taxes impacts inter-generational equality. He stated that the normalization concept prevents the inter-generational inequity that can occur when the flow-through method is used. If NIPSCO uses an immediate or faster flow-through method, current customers receive the entire refund and disproportionally benefit. Returning to his example of the single repairs deduction, under Mr. Blakley's proposal, customers during the first five years see 100% of the benefit from the TCJA, whereas the customers over the remainder of asset's life see none of the benefit although the asset giving rise to the benefit will serve all of them. The WACC is also inequitable for those later customers. He stated that the entirety of the zero-cost excess deferred taxes will have already been returned over the first five years, meaning a higher WACC for the remainder of the life of the asset giving rise to the benefit. Mr. Blakley's and Mr. Gorman's approach is the equivalent of paying the lowest interest loans in the capital structure first rather than the higher interest loans. In this scenario, future customers are unfairly penalized because they may not receive any refund, yet pay for the cost of the utility asset over its remaining useful life. He testified that normalization ensures that tax benefits are spread to all customers who benefit from NIPSCO's long-life assets, not just current customers. He testified that NIPSCO believes that the normalization concept should be applied to unprotected property, and the pass back of these excess deferred taxes should use ARAM.

Mr. McCuen explained how a normalization approach to the return of unprotected property related items impacts the originally anticipated payment to the government. He testified that under a policy of normalization for the return of excess deferred taxes, NIPSCO would be required to pay the money no longer owed to the government to its ratepayers instead, but in approximately the same time pattern as NIPSCO originally expected to pay it to the government.

Mr. McCuen disagreed with Mr. Blakley that ADIT represents a "loan" from ratepayers to the utility because although Mr. Blakely correctly identifies how ADIT is created, ADIT is really an interest-free loan from the U.S. Government. Mr. McCuen cited to a FERC Order finding no reasonable basis for concluding that customers actually provide a loan to their utility. He added that the ARM methodology used by NIPSCO is required by the IRS.

Mr. McCuen testified NIPSCO is currently amortizing the regulatory liability associated with excess deferred taxes using ARAM. He stated this regulatory liability includes excess from pre-TCJA and amounts generated from TCJA. Mr. McCuen reiterated that NIPSCO has continued to follow the guidance provided by the Commission in its June 1, 1987 Interim Order. He explained that the Commission has always approved this approach, most recently in its 44688 Rate Case Order, and this is the proper accounting and regulatory treatment until a new order is issued. He also noted that the filed rate doctrine and prohibition against retroactive ratemaking bar NIPSCO from charging a rate other than the rate properly filed with the Commission, and similarly bar the retroactive imposition of a rate change for service already provided.

L. Mr. Rea. Mr. Rea testified that the ROE recommendations of OUCC witness Woolridge and Industrial Group witness Gorman should be rejected by the Commission. Specifically, Dr. Woolridge recommended that NIPSCO's ROE be set at 8.75% but further proposed that in recognition of the practice of gradualism, a 9.25% ROE would be more appropriate. Mr. Gorman recommended an ROE of 9.35%. In his rebuttal testimony, Mr. Rea demonstrated that the ROE recommendations of Dr. Woolridge and Mr. Gorman would not allow NIPSCO the opportunity to earn a fair return as compared to other electric utility companies. He stated that if these ROE recommendations were adopted, it would send a message to the financial community that Indiana's regulatory climate was not fully supportive of maintaining financially sound utilities, which could have negative implications from a capital attraction standpoint.

Mr. Rea testified that by ignoring the authorized returns of other electric utility companies of comparable risk, Dr. Woolridge and Mr. Gorman have failed to recognize the fair return standards established in the Hope and Bluefield cases. Mr. Rea further stated Dr. Woolridge and Mr. Gorman failed to adequately recognize that U.S. capital market conditions have recently been anomalous and that the Federal Reserve's recent monetary policy interventions have played a contributory role in driving interest rates to all-time lows and the stock market to its all-time high.

Mr. Rea testified that the failure of Dr. Woolridge and Mr. Gorman to evaluate a broader group of non-rate-regulated companies with comparable risks, and which provides useful perspective on the competitive market result, ultimately causes their cost of equity recommendations to be unreliable. He stated that the manner in which they have applied the DCF, CAPM, and Risk Premium models suffer from a number of infirmities. He also stated that their failure to evaluate the expected earned returns of companies with comparable risks results in ROE recommendations that do not adequately recognize the Comparable Earnings standard established in Hope and Bluefield.

Mr. Rea further testified that the recommendations of Dr. Woolridge and Mr. Gorman to: (1) reduce NIPSCO's authorized ROE on the basis of NIPSCO's equity capitalization layer; (2) reduce NIPSCO's authorized ROE due to the implementation of NIPSCO's TDSIC program and other regulatory mechanisms; and (3) deny a return on NiSource's stock issuance flotation costs, should all be unequivocally rejected. He summarized that after reviewing the testimony and analyses of Dr. Woolridge and Mr. Gorman and revisiting his original cost of equity evaluation, he concluded that NIPSCO's cost of equity remains in the range of 10.55% to 11.05%, and that the Commission should adopt a cost of equity at the midpoint of this range, or 10.80%.

Mr. Rea sponsored Attachment 15-R-B, Schedule 2 – Updated, presenting NIPSCO's capital structure as of December 31, 2019, as follows:

Projected Capital Structure as of December 31, 2019

	Balance (000)	% of Total	Cost	WACC
Common Equity	$2,864,884,714	47.85%	10.80%	5.17%
Long-Term Debt	2,151,351,378	35.93%	4.97%	1.79%
Customer Deposits	71,453,491	1.19%	5.15%	0.06%
Deferred Income Taxes	1,266,429,454	21.15%	0.00%	0.00%
Post-Retirement Liability	66,142,914	1.11%	0.00%	0.00%
Prepaid Pension Asset	(435,272,223)	-7.27%	0.00%	0.00%
Post-1970 ITC	2,014,831	0.03%	8.30%	0.00%
Totals	$5,987,004,559	100.00%		7.02%

M. Ms. Strauss. Ms. Strauss addressed proposed bill counts and kWh usage for residential customers, including weather normalization, sponsored by OUCC witness Novak and that clarified the support used as the basis for the derivation of proposed billing determinants sponsored by NIPSCO witness Westerhausen. Ms. Strauss was critical of Mr. Novak's proposed bill counts, contending that they had employed unreasonably high growth rates and as a result producing a residential customer bill count that was excessive. She explained that NIPSCO recommends considering other factors in addition to historic growth levels when forecasting customer counts and reiterated that NIPSCO's method for forecasting residential bill counts relies on market intelligence from the New Business Team and is cross checked by running a regression analysis, which shows that local housing starts are a strong predictor of new residential customers.

Ms. Strauss testified that the only similarity between the weather normalization she sponsored and that discussed by OUCC witness Novak was his proposal to adjust only residential and commercial customer classes for weather due to the correlation between their energy usage and weather. She explained that Mr. Novak's proposed weather normalization adjustment had been developed outside of the regression modeling used to produce NIPSCO's forecasted usage, and thus could not be applied to NIPSCO's forecast. She testified that the OUCC recommendation of 3,616,043,140 kWh for the residential customer class for 2019 included a weather normalization adjustment of 158,919,910 kWh (almost 4.4% of the total) and a growth adjustment of 172,942,640 kWh (more than 4.7% of the total) and that the forecast was unreasonably high. She noted that Mr. Novak's projected Forward Test Year residential usage per customer was above NIPSCO's historic annual usage per customer even when that annual usage per customer is calculated using the OUCC excessive bill count. She testified that NIPSCO's forecasted 2019 residential usage of 8,286 kWh per year is below the actual 2016 usage and consistent with the trend of decreasing usage per customer observed from 2012 through 2016. She concluded that NIPSCO's demand forecast is based upon econometric analyses and statistically significant regression results, is more reasonable and reflective of actual experience on NIPSCO's system, and should be approved.

N. Mr. Rimal. In rebuttal, Mr. Rimal discussed the changes to some of the special studies used for cost allocation that he had conducted for his direct testimony. He stated these changes are driven by three primary factors: (1) the migration of a sixth customer into Rate 831; (2) the assumption that customers that would have been moved to the new Rate 830 will remain with their original rate schedules (now Rates 832 and 833); and (3) revisions to the test year projected billing units associated with Rates 721, 723, 724, and 726 to reflect customers that have migrated between rate schedules.

O. Dr. Gaske. In rebuttal, Dr. Gaske responded to issues raised by OUCC witness Watkins, NLMK witness Lahtinen, Industrial Group witness Phillips, US Steel witness Georgis, CAC witness Wallach, Sierra Club witness Allison, and Walmart witness Chriss. He also updated the ACOSS and addressed associated rate design and bill impacts for changes in NIPSCO's revenue requirement.

Dr. Gaske noted that Mr. Phillips and Mr. Lahtinen agreed with the 4CP method for the allocation of production costs because NIPSCO is a strong summer-peaking utility and Mr. Lahtinen asserted that this approach will help combat bypass by the large customers. In response to Mr. Watkins recommendation that either the BIP, P&A, or 12CP methods would result in a reasonable allocation of NIPSCO's demand-related production costs, Dr. Gaske testified that these methods would allocate greater costs to the new Rate 831 industrial class that will consist of customers who will purchase only a minor portion of their power from NIPSCO. He testified that he used the 4CP method for NIPSCO because in recent years, the system peaks in the months of June – September were almost always within 90% of the annual peak, but none of the other eight months were ever within 90% of the annual peak. He disagreed with Mr. Watkins that the 4CP does not recognize the investment or operational characteristics of NIPSCO's generation portfolio as it allocates the total generation plant investment based on a few peak hours of the year. He also showed that Mr. Watkins incorrectly assumed that NIPSCO's baseload facilities have higher capacity costs than intermediate or peaking facilities. This incorrect assumption that baseload plant achieves lower energy costs by incurring higher capacity costs led Mr. Watkins to conclude that the BIP or P&A methods are more appropriate because he assumed that they recognize the fact that the baseload generation resources are utilized at a very high capacity factor to meet the energy needs throughout the year. Dr. Gaske explained that once installed, any generation asset may be available for dispatch at any time. He stated that while Mr. Watkins is correct that utilities typically consider a tradeoff between capacity costs and energy costs when they first construct a plant, circumstances change and the relative costs of fuel and the efficiencies of different types of capacity can change significantly over time. He stated that the assumption that NIPSCO incurred higher capacity costs in order to achieve lower energy costs for its baseload units is not correct.

Dr. Gaske also disagreed with Mr. Watkins' criticism of the FERC tests to determine the reasonableness of 4CP allocator noting that his criticism is based solely on the fact that the tests were developed by FERC. He stated that the FERC tests are a commonly used method for analyzing system load characteristics and determining whether a utility has monthly peak periods that can be distinguished from off-peak periods and that establishing the extent to which such a distinction exists provides a basis for determining the time periods which are most relevant for production and transmission capacity cost incurrence.

Dr. Gaske also responded to Mr. Watkins testimony that the 4CP peak hours occurred during mid-afternoon summer hours when certain commercial heating (Rates 720 and 722) and the lighting (Rates 750 and 760) services are not using any electricity and his criticism of the 4CP method because it does not allocate any generation capacity costs to those services. He stated that to the extent that these heating and lighting services are off-peak and do not cause or contribute to the need to construct additional generating plant, it is not unreasonable that they should receive little or no allocation of generating plant costs. He noted that the commercial heating services are small, ancillary services that are used by customers who take their primary electric service under other rates that do have an allocation of generating plant costs and that the total bills paid by these customers are designed to cover the costs of providing their services.

Dr. Gaske testified that Mr. Watkins concluded that the 12CP method is reasonable for allocating transmission costs. He testified that although Mr. Georgis' proposal to sub-functionalize the transmission facilities might be more accurate, all ratemaking involves some degree of averaging of costs of different facilities and customer characteristics. Thus, this issue basically reduces to a question of how far to go in de-averaging rates and recognizing individual differences. In Dr. Gaske's opinion, the method proposed by NIPSCO is reasonable, and he did not propose to change that method in his updated, rebuttal calculations.

In response to Mr. Allison's argument that minimum system distribution costs are not clearly a function of the number of customers because if a customer has zero demand, then there is no need to build any distribution infrastructure, Dr. Gaske testified that the minimum system analyses used by Mr. Rimal are based on the assumption that there is a minimum-sized distribution system required to be capable of serving minimum requirements of customers. He stated that this minimum system cost is dependent primarily on the number and location of customers, not on the peak demand the customers place on the system. He responded that the zero-demand assumption that Mr. Allison invokes is relevant under the "zero-intercept" or the "minimum-intercept" method, which seeks to identify the portion of the plant that is related to a hypothetical no load situation, but it is not relevant for the minimum system method that is used in Mr. Rimal's study.

In response to Mr. Allison's argument that if a new customer is added to an already populated area, there are no additional secondary distribution costs unless that customer increases the peak demand on the distribution system and, therefore, the cost is driven by demand and not the number of customers, Dr. Gaske testified that does not mean that the entire distribution system cost should be classified as being demand-driven. He stated that a portion of the distribution system that was existing before a customer is added is required to serve the minimum requirements of the customers and their geographic dispersion. He explained that the whole point of conducting a minimum system analysis is to calculate the portion of the distribution system that does not vary by demand because a portion of the distribution costs are incurred regardless of the peak demand of the customers. He noted that increases or decreases in demand do not result in proportionate increases or decreases in the number of poles and miles of conductors required to distribute electricity. He explained that a portion of the distribution system costs are classified as customer-related because the distribution system exists to deliver electricity to hundreds of thousands of customers who are widely dispersed. He said that a significant portion of those costs are totally unrelated to the peak demand and, thus, should not be allocated based on demand. He noted that Mr. Allison appears to agree that minimum system costs could reasonably be allocated to classes

based on the number of customers, but Mr. Allison more strongly objects to inclusion of those costs in the customer charge for rate design purposes.

Dr. Gaske disagreed with Mr. Wallach's assertion that the minimum secondary distribution cost per customer is overstated by a minimum system study. He stated that distribution system costs are incurred to move electricity from generation and transmission facilities to individual customers that are distributed geographically throughout the NIPSCO service territory. He noted that Mr. Wallach is correct that some portion of the distribution system costs vary with demand, which is why the ACOSS classifies a portion of the costs as demand-related, but it is incorrect to assume that all distribution system costs are demand-related.

In response to Mr. Wallach's statement that distribution equipment that carries zero load can serve an infinite number of customers with zero load, Dr. Gaske agreed that an infinite number of customers could be served by the NIPSCO distribution system if each customer has a demand approaching zero. However, NIPSCO is allocating the costs to the customers that are actually served by its distribution system. He stated again that the minimum system method is based on the premise that a minimum size distribution system is required to deliver electricity to the geographically dispersed customers that are actually on the NIPSCO system, and the costs of this minimum system is unrelated to either peak demands or total energy usage. He noted that although the minimum system costs per customer would be lower for a utility that serves a more densely populated territory, it is still reasonable for the customers to share those costs equally because a large portion of distribution system costs are related to reaching the numerous, geographically dispersed customers, and those minimum system costs are unrelated to peak demand.

Dr. Gaske disagreed with Mr. Wallach's claim that all line transformer costs had been classified as customer-related and his argument that a portion of these costs should be classified as demand-related. Dr. Gaske stated that line transformers are at the intersection of the distribution system and the customer premises and, like meters and services, are designed for the specific customer or customers at a location. For that reason, these costs are largely related to the number of customers. He stated that, more importantly, the line transformer costs (Account 368) are not allocated based on a simple allocation by number of customers but instead, a weighted customer allocation was developed based on the types of transformers and costs used to serve each class. This weighted approach allocates 4.5 times as much per customer to commercial customers than residential customers, which implicitly reflects the greater demand and more accurately reflects the higher cost of transformers for commercial customers. He testified that approximately 96% of these line transformer costs are allocated to the residential and small commercial classes, which do not have demand meters. Thus, once allocated to the classes based on their different weighted costs per customer, it is most appropriate to recover these costs in the customer charge because the costs are fixed regardless of a customer's energy use.

Dr. Gaske disagreed with Mr. Georgis' recommendation that transmission-related revenue in Account 456 should be allocated to the various rate classes in the same manner that transmission costs are allocated (i.e., the 12CP method). He testified that he used the amount of revenue margin (i.e., revenue excluding fuel costs) for each class as an allocator to allocate and credit Account 456 transmission-related revenues to the various classes. He explained that these revenue credits are used to offset the fixed costs incurred by all classes on an equal basis relative to their contributions to the revenue margin. He stated that although the approach proposed by Mr. Georgis is not

unreasonable, it is also reasonable to continue to treat the transmission revenues as a general source of funds available to offset the overall costs of serving all classes on a pro rata basis.

Dr. Gaske disagreed with the rate mitigation strategies proposed by Mr. Wallach, Mr. Watkins, and Mr. Chriss. He testified that with the possible exception of Mr. Chriss, each of these witnesses appears to agree that increasing all rate classes except Rate 831 by an equal percentage is reasonable. He noted that, as discussed by NIPSCO witness Kelly, the proposals to allocate either more or less costs to Rate 831 would not be consistent with the balance between competing interests and competitive pressures that NIPSCO is trying to achieve in its proposed industrial service restructuring, cost allocation, and mitigation. Importantly, he noted that the proposed Rate 831 revenue requirement is not a discounted rate but instead, the Rate 831 revenue requirement is set equal to the fully allocated cost of service.

In response to the objections of Mr. Wallach, Mr. Watkins, and Mr. Allison to the implementation of an SFV rate design concept, Dr. Gaske testified that although an SFV rate design would provide better price signals for efficient usage, he is not proposing an SFV price structure for NIPSCO's residential and commercial customers at this time. Instead, a substantial amount of fixed costs would continue to be recovered in the energy charge and the marginal price of consumption generally will exceed the marginal cost of production by a large amount. He testified that while he disagrees with their assertions and interpretations concerning the theory of efficient pricing, in reality NIPSCO's proposed rate structure would recover only a small fraction of residential and small general service fixed costs in the customer charge and as a result, many of their theoretical arguments are misdirected.

Dr. Gaske disagreed with the arguments that the energy rate should be based on long-run marginal costs and as a result, it is appropriate to recover demand-related costs from residential customers in the variable energy rate in proportion to their energy use. He testified that fixed, demand-related production and transmission costs are typically driven by the coincident peak demand while demand-related distribution costs are generally driven by the non-coincident peak demand on different parts of the system. He stated NIPSCO incurs these costs to meet peak load; therefore, they are not based on the total amount of kWh a given customer consumes. He noted that customer coincident and non-coincident peak loads are a significant driver of the costs of NIPSCO's distribution system.

Dr. Gaske also disagreed with claims that recovering a small portion of demand-related costs in the customer charge and less than 100% of such costs in the energy rate would result in cost subsidization within the residential class and would dampen energy price signals to consumers for controlling bills through conservation, EE investments, or distributed renewable generation. He testified that the production and delivery of electricity consists of both fixed costs and variable costs. He explained that when a rate structure recovers fixed costs in variable energy charges, as Mr. Wallach, Mr. Watkins, and Mr. Allison recommend, the rate structure overstates the marginal cost of electricity and discourages consumption that would be efficient because the marginal benefit of consuming additional units of electricity exceeds the marginal cost of the energy required to produce that electricity. He stated these witnesses' concepts of conservation and efficiency appear to be narrowly focused on attempting to discourage electricity use and encourage consumption of alternative resources, but electricity use provides enormous benefits to consumers

and the community, and consumers require proper price signals as to the marginal cost of electricity to make decisions that improve the welfare of themselves and the community.

In response to Mr. Watkins' claims that the price signal that results from SFV pricing is meant to promote additional consumption, Dr. Gaske testified that it is more accurate to say that this type of rate design is meant to promote efficient consumption by allowing alternative energy sources to compete on the basis of their marginal fuel cost without the distortion of trying to collect fixed costs through a variable energy charge. Regarding FERC Order No. 636, Dr. Gaske indicated that FERC placed all of the fixed costs in a demand charge so that recovery of fixed costs in the volumetric charge would not distort the price signals in the commodity cost of energy and thereby improve competitive efficiency in the market. He stated that for customers with demand meters, NIPSCO is generally proposing to recover the demand-related fixed costs in a demand charge, and the customer-related fixed costs in a customer charge so that the energy charge is close to the utility's variable cost of fuel and energy thus promoting efficiency because it charges customers based on the costs they cause the utility to incur. Dr. Gaske disagreed with Mr. Watkins' discussion on theoretical pricing in competitive markets noting that Mr. Watkins neglects the fact that many competitive industries use multi-part rates to properly reflect costs and dimensions of service.

Dr. Gaske presented updated cost of service and rate design schedules assuming separate small industrial rates are retained for low load factor and high load factor service. He stated that in these schedules, proposed Rate 832 comprises those industrial customers currently taking service under Rate 732 that will not be moving to the proposed large industrial Rate 831, and proposed Rate 833 is comprised of customers currently taking service under Rate 733 that will not be moving to proposed Rate 831. He listed all the changes that were incorporated into the updated ACOSS and rate design as: (1) an update to the revenue requirements; (2) the assumption that customers that would have been moved to the new Rate 830 will remain with their original rate schedules (832 and 833); (3) the migration of a sixth customer into Rate 831 with a reduction in that customer's expected 4CP demand and billing unit; and (4) revisions to the test year projected billing units associated with Rates 721, 723, 724, and 726 to correctly reflect customers that have migrated between rate schedules. He concluded that in general, these changes had a *de minimis* effect on the rates that NIPSCO is proposing for the various classes.

P. Mr. Westerhausen. In response to Industrial Group witness Phillips' concerns with NIPSCO's proposed Rate 830, Mr. Westerhausen testified that NIPSCO is willing to develop two separate rates, both a load factor rate and a high load factor rate for those current customers receiving service on Rate 732 and Rate 733 not opting, or eligible, for Rate 831 service. He stated that to prevent an unintended adverse impact on NIPSCO's low load factor customers, NIPSCO is willing to continue a Rate 732 low load factor service (now proposed Rate 832) and a Rate 733 high load factor service (now proposed Rate 833). He explained that these new rates will include the Back-Up, Maintenance, and Temporary Service that was proposed in Rate 830. He stated that Appendix A has been revised to reflect new Rates 832 and 833. He testified that in its compliance filing to implement Step 1 rates, NIPSCO will update its Series 800 Tariff to address the removal of Rate 830 and the addition of Rates 832 and 833.

Mr. Westerhausen also testified that a transition service that expires on May 31, 2020, has been added to both Rate 832 and Rate 833 for customers that intend to move to proposed Rate 831 but will not be ready when the new rate schedules go into effect. He explained that these customers

will be required to maintain their historical interruptible capacity through the current MISO Planning Year and that the maximum capacity contract limit of 25,000 kW will not go into effect until June 1, 2020. He stated that language from NIPSCO's current Rider 775 for Character of Service, Curtailment, and Interruption limits, Interruptions, Energy Charges and Customer's Failure to Comply with Requested Interruptions or Curtailment has also been added to both rates.

Mr. Westerhausen responded to US Steel witness Thornton's concerns that: (1) although most of the riders are straightforward with respect to calculation and application, there are concerns about possible cost shifting depending on customers' Tier 1, Tier 2, and Tier 3 firm capacity elections; (2) it is not clear whether the energy and demand tracker allocators will be trued up once the large industrial customers have made final firm capacity elections; and (3) truing up tracker allocators is necessary to avoid possible inter-class subsidies and over-collection of costs. Mr. Westerhausen testified that: (1) NIPSCO will true up the energy and demand tracker allocators with the final Tier 1, 2, and 3 contracts; and (2) there were no changes to NIPSCO's proposal for the allocation of its various trackers to the different tiers of service within Rate 831 – the methodology is the same as what NIPSCO presented in its case-in-chief, but the proposed tracker allocations were updated to reflect the rebuttal ACOSS, which includes the rebuttal revenue requirement and the migration of one additional customer to proposed Rate 831.

Mr. Westerhausen addressed an update to the Rate 831 billing determinants. He stated one additional large customer is being migrated from proposed Rate 830 to proposed Rate 831, resulting in an additional ten MW of Rate 831 Firm Demand, 86,597,913 kWh Tier 1 energy, and 63,271,988 kWh Tier 2/3 energy. He explained that Tier 1 energy was calculated by using 2017 actual 30 minute kW meter readings and by allocating the lessor of ten MW or their actual demand into Tier 1 energy, and the remaining if their actual demand was greater than ten MW into Tier 2/3 energy. He said the 2017 monthly total energy was then compared to the 2019 forecasted monthly energies and since the 2017 Tier 1 energy was at a 99.9% load factor, the monthly energy difference from 2017 actuals to the 2019 forecast was added to Tier 2/3. He stated that because the additional 63,271,988 Tier 2/3 energy will no longer be sourced from NIPSCO generation, a reduction to the Forward Test Year electric operating revenues was made for an additional $1,629,317 of fuel expense reduction (Adjustments REV 1-R and FP 1-R). He stated the total adjustment reflected in REV 1A-R-19SS and FP 1A-R-19SS of $85,260,118 reflects all changes in industrial fuel based on the proposed new service structure. He noted that if this adjustment is not included, Forward Test Year electric operating revenues would be overstated and that if NIPSCO's service structure is not approved, this balance will need to be updated.

Mr. Westerhausen described two revisions to Rate 831. The first revision allows customers who are not ready to take service under Rate 831 on its effective date to take service under Rate 832 or Rate 833 through May 31, 2020. The second revision is related to the MISO Curtailment and Firm Capacity Options to provide at least two hours advance notice of MISO curtailments.

Mr. Westerhausen testified there is one revision to Rider 876 to clarify that service under Rider 876 cannot be used to nullify some or all of a MISO LMR obligation to curtail. Mr. Westerhausen supported Adjustment REV 1J-R-19R to increase Forward Test Year electric operating revenues in the amount of $2,187,672 to reflect the reallocation of commercial and small industrial customer revenues resulting from reallocation of the demand forecast utilizing 2018 actual billing determinants.

In response to Mr. Chriss' concerns with the Rate 726 class load profile data and 2019 billing determinants, Mr. Westerhausen testified that although the forecasted Billing Determinants in Total for Commercial and Small Industrial Customer Classes vary by less than 2%, there are material differences in the allocation between Rates 721, 723, 724, and 726. He stated that this misallocation was partially driven by a significant amount of customer migrations to Rate 726 between 2016 and 2018. Therefore, an adjustment was necessary to reallocate those billing determinants between those four rates based on 2018 allocation factors. He stated that the same methodology used by Financial Planning to allocate forecasted energy billing determinants by customer class to individual rates and blocks was utilized. He explained that billing determinants are planned for customer count, Demand (kW), and Energy (kWh) by rate. He described that this is completed within six rate classes – Residential, Commercial, Small Industrial, Large Industrial, Lighting, and Other. Forecasted customer count and kWh are provided by customer class by Demand Forecasting. He stated the Demand Forecast customer count and kWh are then passed to Financial Planning, where they are allocated to the individual rates and blocks, except for the Large Industrial Forecast, which is provided separately by customer. The allocation methodology uses billing data from a historical test period and their relationships to allocate the forecasted kWh and customer count to the rates and blocks. For the 2018 and 2019 budgets, the 12 months ended December 2016 was used as the historical test period, which was the last year end prior to the planning process. Mr. Westerhausen explained that demand is forecasted based on the percent change in kWh forecast as compared to the kWh in the test period. He noted that same percentage is applied to the kW in the test period to get forecasted kW for the budget. He explained that Adjustment REV 1J-R-19R kept the forecasted billing determinants for Rates 721, 723, 724, and 726 the same in total, but reallocated them between the four rates based on the 12 months ended December 31, 2018 actuals. He noted that the same allocation methodology was used to reallocate the forecasted kW between these four rates rather than using the growth factor performed by Financial Planning. He stated that the reason for this deviation from the planning process is that they already had established a reasonable amount of kW in total, and reallocating the forecasted kW resulted in reasonable results compared to 2018 actuals. He noted that these allocations were performed for the Commercial Class and Small Industrial Class, but did not change the Large Industrial or Other Customer Classes.

Mr. Westerhausen described Adjustment Rev 1E-R-19R and FP 1E-R-19R. He stated that NIPSCO proposed an adjustment for small migrations in its case-in-chief to annualize small customer migration that occurred in 2017 and the first half of 2018, which was necessary in the case-in-chief because the billing determinants for test year 2019 were based on the AFP, which used calendar year 2016 to allocate forecasted billing determinants by customer class to rates. He stated that an adjustment was made to the 2019 AFP to reallocate forecasted billing determinants based on 2018 actuals (see Adjustment Rev 1J-R-19R for further detail). He stated that since 2018 actual allocation of billing determinants was used to restate individual rate billing determinants, that process accounted for any 2017 and 2018 customer migrations that had occurred through December 31, 2018. As such, the small customer migration adjustment is no longer applicable and is being removed from rebuttal adjustments for billing determinants, revenues, and fuel.

Mr. Westerhausen testified the average system fuel was calculated by using the total fuel and purchase power of $321,765,239 divided by total fuel kWh of 12,034,825,315, resulting in an average fuel cost of .02674/kWh.

Mr. Westerhausen sponsored Attachment 19-R-L, an update to Attachment 19-C (Revised), which shows 2017, 2018, and 2019 billing determinants. He stated that Attachment 19-R-L was also updated for the additional migration of a large industrial customer currently served under Rate 833 to Rate 831, Plan Allocation in Adjustment REV 1J-R-19R, and reversal of Small Migration in Adjustment REV 1E-R-19R, and also included a correction to Rate 721 2019 kWh billing determinants. He noted that the 2,123,333 kWh for the 2019 Weather Normalization adjustment shown in Column K was not included in the 2019 Projected Billing Determinants Column M and that this correction results in the 2019 revised billing determinants decreasing by 2,123,333 kWh. He indicated that Attachment 19-R-L also included six insignificant corrections to 2017, 2018, and the starting kWh in Column I of 2019 Budget Billing Determinants that did not affect the 2019 billing determinants.

Mr. Westerhausen sponsored Attachment 19-R-M, NIPSCO's proposed standard contract for service. He stated the agreement has been revised from the proposed standard contract for the removal of Rate 830 and Rate 831 and added references to Rates 832 and 833. He also sponsored Attachment 19-R-O, NIPSCO's proposed standard contract for service for Rate 831 incorporating Tier 1, 2, and 3 contract demands and aggregation information specifically for this rate.

20. Overview of the Revenue Settlement. The Revenue Settlement entered into by and among NIPSCO, Industrial Group, NLMK, US Steel, CAC, Walmart, NICTD, Sierra Club, IMUG, and the OUCC resolves revenue requirements issues and other miscellaneous issues. The key terms of the Revenue Settlement are summarized as follows:

- NIPSCO's base rates will be designed to produce $1,482,166,740 prior to application of surviving Riders, which represents a decrease of approximately $63.648 million from the amount originally requested by NIPSCO. The revenue requirement reflects the depreciation study and accrual rates and amortization and a $2,000,000 decrease to NIPSCO's proposed O&M Expense. The agreed revenue requirement does not include:
    - All MISO related costs not included in FAC charges which had been recovered through base rates. Those costs shall be recovered instead through the RTO tracker; and
    - Costs related to the URT are removed from base rates. The URT shall be calculated and recovered as a separate line item on customer bills.
- NIPSCO's authorized NOI will be $271,211,585.
- The Revenue Settling Parties agreed that the WACC times NIPSCO's original cost rate base yields a fair return for purposes of this case, and agree that NIPSCO should be authorized a fair return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets as proposed in NIPSCO's case-in-chief (unless corrected in this proceeding); (2) NIPSCO's proposed capital structure as set forth below; and (3) NIPSCO's authorized ROE of 9.90%.

- NIPSCO's overall WACC is computed as follows:

	Dollars	Cost %	WACC %
Common Equity	$2,864,884,714	9.90%	4.74%
Long-Term Debt	$2,151,351,378	4.97%	1.79%
Customer Deposits	$71,453,491	4.91%	0.06%
Deferred Income Taxes	$1,266,429,454	0.00%	0.00%
Post-Retirement Liability	$66,142,914	0.00%	0.00%
Prepaid Pension Asset	$(435,272,223)	0.00%	0.00%
Post-1970 ITC	$2,014,831	8.30%	0.00%
Totals	**$5,987,004,559**		**6.59%**

- The depreciation accrual rates recommended by NIPSCO witness Spanos and presented in the Depreciation Study should be approved except that: (1) the amortization period for retired coal-fired generating units described in NIPSCO's case-in-chief shall conclude in 2032, which presumes the retirement of Schahfer in 2023 and the Michigan City in 2028; and (2) annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency expense included in demolition costs, as proposed by Industrial Group witness Gorman.

- NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding except that the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC Seven-Year Plan, FMCA, MATS, EDR, and Electric Rate Case Expense of seven years. If not already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

- NIPSCO agrees to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base at the time a final order is issued in this proceeding and the actual investment amount adjusted for depreciation as outlined in OUCC witness Blakely's direct testimony. NIPSCO agrees to implement the credit upon the retirement of the generating units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. The credit will be limited to the net plant investment value of the Schahfer and Michigan City generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in paragraph B.1(a); and (2) the NOI established in paragraph B.1(b) for purposes of its earnings test. NIPSCO agrees to hold annual pre-filing meetings preceding the 30-day compliance filing with interested stakeholders.

- The Revenue Settling Parties agree that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in

NIPSCO's revenue requirement at the ARAM, estimated at the time of this Agreement to be 26 years.

- The Revenue Settling Parties agree that NIPSCO's Unprotected and Other Excess ADIT balance, totaled approximately $137,789,071 as of December 31, 2017. NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. If not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization.

- Step 2 Rates shall be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agrees it shall not be permitted to include in rate base for Step 2 Rates plant in excess of the amount or value of plant projected in this Cause. The Revenue Settling Parties agree that Step 2 Rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Step 2 Rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019, and calculate the Step 2 Rates using those certified figures. NIPSCO will provide all Revenue Settling Parties with its certification. The Revenue Settling Parties and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Revenue Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 Rates were put into place.

- The Revenue Settling Parties agreed to the following issues related to rate design:

    - Rates should be designed with the Residential Customer Charge set at $13.50/month;

    - as proposed in Industrial Group witness Phillips' direct testimony and NIPSCO witness Westerhausen's rebuttal testimony, Rate 830 shall be split into Rates 832 and 833 which shall reflect the current structure of Rates 732 and 733, and provide for back-up and maintenance provisions reflected in current Rider 776; and

    - Rate 844 shall see no increase in its base rates resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago.

- The Revenue Settling Parties agreed to the following tracker and rider issues:

- NIPSCO agrees to flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero.
- NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years.
- NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief.

- NIPSCO commits to seek approval of a voluntary low-income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process NIPSCO has already established with interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

- The lamp charge for TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. The resulting revenue deficiency (estimated at NIPSCO's proposed COSS to equal approximately $52,500) will be allocated to other customer and NIPSCO-owned lamp types in Rate 850.

21. Revenue Settlement Supporting Testimony.[35]

A. NIPSCO Witness Sistovaris. Ms. Sistovaris and the other Revenue Settling Parties sponsored Joint Exhibit 1, which is a copy of the Revenue Settlement in this Cause, including the Formal Notice of Indiana Municipal Utility Group Joinder in Amended Partial Settlement Agreement filed May 15, 2019. She testified the specific objectives addressed in the Revenue Settlement include: (1) resolution of the revenue requirements issues; (2) resolution of issues related to the Residential Customer Charge; (3) resolution of issues relating to proposed Rate 830; (4) resolution of issues related to the impact on proposed Rate 844 customers; (5) resolution of issues relating to proposed Rate 850; (6) resolution of issues related to NIPSCO's proposals relating to proposed Riders 871, 872, and 877; and (7) resolution of issues relating to creation of a low-income program.

Ms. Sistovaris summarized the differences in the proposed revenue requirements among the parties. She testified that NIPSCO filed this case to: (1) reflect the evolution of the market for electricity for NIPSCO as well as for its largest customers in NIPSCO's service structure; (2) reflect in base rates the recent capital investments into NIPSCO's electric system, including infrastructure modernization and environmental controls; (3) revise its depreciation rates; and (4) align its rates and charges required to maintain safe and reliable service. She stated the majority of

[35] Sierra Club filed a notice of support for the Revenue Settlement stating that the direct and cross-answering testimonies of Ms. Allison to support the overall reasonableness of the fixed charge for residential service and the acceleration of depreciation for NIPSCO's coal-burning units.

the differences in the proposed revenue requirements among the parties can be reduced to three issues: (1) NIPSCO's authorized ROE; (2) NIPSCO's need to address unresolved impacts related to the TCJA, particularly the return of excess ADIT; and (3) NIPSCO's efforts to mitigate the effects of the requested change in depreciation rates. Additionally, there were other proposed differences to the revenue requirement related to proposed amortization periods for various regulatory assets and differences in pro forma operating costs.

In support of the agreed-upon ROE and the resulting authorized NOI, Ms. Sistovaris stated there was a balancing of interests among NIPSCO's stakeholders. She noted that too low of a return would provide a level of financial insecurity that would place inappropriate risk upon NIPSCO's ability to attract capital to provide reasonably adequate service and facilities. However, NIPSCO recognizes that returns have trended downward since its last rate case order. She stated that balancing the interest of all stakeholders, the Revenue Settling Parties agreed upon an ROE of 9.90%, which is lower than NIPSCO's requested ROE but higher than the ROE proposed by the OUCC, the Industrial Group, and Walmart.

In support of the agreed-upon treatment of the return of excess ADIT, Ms. Sistovaris stated the Revenue Settling Parties agreed that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460), shall be passed back in NIPSCO's revenue requirement at the ARAM, estimated at the time of the Revenue Settlement to be 26 years. She stated that the Revenue Settling Parties also agreed that NIPSCO's Unprotected and Other Excess ADIT balance (totaled approximately $137,789,071 as of December 31, 2017) shall be amortized $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. The Revenue Settling Parties agreed that at the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. Finally, NIPSCO agreed that if not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO will make a tariff filing that will reflect the ending of the amortization.

In support of the agreed-upon resolution of NIPSCO's request to modify its depreciation rates and cost recovery in rates, Ms. Sistovaris stated that the Revenue Settling Parties agreed to the depreciation accrual rates recommended by Mr. Spanos and presented in the Depreciation Study with two exceptions. First, those proposed depreciation rates are expected to result in a regulatory asset to be included in rate base and amortized over a period of years as described in NIPSCO witness Shikany's direct testimony. The Revenue Settlement provides that the amortization period of that regulatory asset shall conclude in 2032. Second, annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency expense included in demolition costs, as proposed by Industrial Group witness Gorman.

Ms. Sistovaris testified the Revenue Settling Parties agreed that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding, except that the amount of annual amortization expense shall be modified to reflect an amortization period for the TDSIC Remand, TDSIC Seven-Year Plan, FMCA, MATS, EDR, and Electric Rate Case Expense of seven years. She stated that NIPSCO agreed that if not already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO will make a tariff filing that will reflect the reduction in amortization expense.

Ms. Sistovaris stated the Revenue Settling Parties agreed that NIPSCO would implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base and rates resulting from the final order in this proceeding and the actual investment amount adjusted for depreciation as outlined in Mr. Blakely's direct testimony and also agreed to implement the credit upon the retirement of the generating units. She described the credit will be limited to the net plant investment value of the Schahfer and Michigan City generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. She explained that NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in the Revenue Settlement (paragraph B.1(a)); and (2) the NOI established in the Revenue Settlement (paragraph B.1(b)) for purposes of its earnings test. NIPSCO also agreed to hold annual pre-filing meetings preceding the 30-day compliance filing with interested stakeholders.

Ms. Sistovaris testified NIPSCO agrees that a NOI of $271,211,585 is an acceptable return on the fair value of its assets. With regard to the proposed changes to Rate 811, Ms. Sistovaris testified the Revenue Settling Parties agreed that the customer charge for Rate 811 will be $13.50 per month. She explained that for purposes of this proceeding, NIPSCO is willing to reduce its customer charge based on the result of a compromise between NIPSCO, CAC, and the OUCC.

With regard to the proposed changes to Rate 830, Ms. Sistovaris testified the Revenue Settling Parties agreed that as proposed in Mr. Phillips' direct testimony and Mr. Westerhausen's rebuttal testimony, Rate 830 will be split into Rates 832 and 833 which will reflect the current structure of Rates 732 and 733, and provide for back-up and maintenance provisions reflected in current Rider 776.

With regard to the proposed changes to Rate 844, Ms. Sistovaris testified the Revenue Settling Parties agreed that Rate 844 will see no increase in its base rates resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. She explained that NICTD, a regional commuter rail authority uniquely situated among NIPSCO's customers, is NIPSCO's only customer taking service under proposed Rate 844. She stated that NIPSCO believes that any unnecessary financial burden on NICTD will have a direct impact on economic development in the region. She noted that NICTD provides a vital transportation function within northwest Indiana directly adjacent to Chicago allowing for thousands of commuters from this region to travel to and from work in Chicago, funneling hundreds of millions of dollars of earned wages into the area each year.

Regarding proposed changes to Rate 850, Ms. Sistovaris testified the Revenue Settling Parties agreed that the lamp charge for TDSIC Light-Emitting Diode ("LED") NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. She explained the resulting revenue deficiency will be allocated to other customer and NIPSCO-owned lamp types in Rate 850 and that NIPSCO recognizes the important public service benefits that municipal street lighting provides and the individual efforts of IMUG in initiating and supporting the LED modernization of NIPSCO street lights. She testified the Rate 850 outcome is reasonable.

Ms. Sistovaris addressed proposed changes to NIPSCO's Tariff resulting from the Revenue Settlement by stating the Revenue Settling Parties agreed that: (1) NIPSCO will flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; (2) NIPSCO

shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years; and (3) NIPSCO's proposal for treatment of economic development rider contracts in Rider 877 shall be approved, including the deferral mechanism described in NIPSCO's case-in-chief.

Ms. Sistovaris testified the Revenue Settling Parties agreed that NIPSCO will seek approval of a voluntary low-income program within six months of a final order in this proceeding. She explained that other program details will be established in good faith through the collaborative process NIPSCO has already established with NIPSCO and interested stakeholders. She stated NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. She said funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

Ms. Sistovaris explained that NIPSCO initiated this proceeding to address three main drivers: (1) to change depreciation rates; (2) NIPSCO needed to address the impact of the TCJA, and; (3) NIPSCO is proposing a change in its large industrial service structure to address the changing economic landscape. She commended the efforts of all Revenue Settling Parties that led to the Revenue Settlement in the abbreviated time permitted by General Administrative Order 2013-5 and Ind. Code § 8-1-2-42.7 and stated the Revenue Settlement was only possible because of the collaborative and open efforts of all Revenue Settling Parties. She stated the Revenue Settlement represents a diligent effort by all Revenue Settling Parties to reach a comprehensive result. She explained that the complexity of the issues and the diversity of the Revenue Settling Parties dictated the need for compromise on the part of everyone involved, and the Revenue Settlement reflects a delicate balance that accommodates the interests of all Revenue Settling Parties in a reasonable way.

Ms. Sistovaris testified approval of the Revenue Settlement as it is written is consistent with the public interest. She stated that as the evidence reflects, the Revenue Settlement resolves complex, divisive, and controversial issues surrounding revenue requirement and a few other issues. Moreover, the Revenue Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost.

B. NIPSCO Witness Shikany. Ms. Shikany supported the Revenue Settling Parties agreement that NIPSCO should be authorized to implement its basic rates and charges for electric utility service in two steps: (1) the first change in rates will be based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in service, actual capital structure, and associated depreciation and amortization expense as of June 30, 2019 ("Step 1"); and (2) the second change in rates will be based on the agreed revenue requirement as of December 31, 2019, as adjusted, if necessary, to reflect the lesser of (a) NIPSCO's forecasted test-year-end rate base as updated in its rebuttal evidence ($4,115,502,071), or (b) NIPSCO's certified test-year-end net plant in service as of December 31, 2019 ("Step 2") and includes the amortization of $12,170,384 per year in the revenue requirement related to the pass back of the unprotected property and other unprotected excess ADIT to customers.

She stated that the Step 1 revenue requirement reflects NIPSCO's projected net utility plant in service, projected capital structure and the associated depreciation and amortization expense as of June 30, 2019, and maintains the amortization of the protected property excess ADIT using ARAM and unprotected property and other unprotected excess ADIT using ARAM and ten years, respectively. She explained that the Revenue Settlement provides for amortization to increase at Step 2 to reflect the pass back of $12,170,384 per year, and that Step 1 rates will go into effect on the next billing cycle following NIPSCO's submission of its Step 1 compliance filing.

She stated that the Step 2 revenue requirement reflects NIPSCO's projected net utility plant in service, projected capital structure and the associated depreciation and amortization expense as of December 31, 2019 and contains the additional pass back of the unprotected property and other unprotected excess ADIT and that Step 2 rates will be certified and go into effect, subject to refund, on March 1, 2020.

Ms. Shikany described the settlement adjustments agreed to by the Revenue Settling Parties. She testified that NIPSCO also updated the Costs of Customer Deposits and the Post-1970 ITC to correct clerical errors made during settlement negotiations, both of which had no impact on the overall WACC agreed to by the Revenue Settling Parties.

In summarizing the Step 2 revenue requirement, Ms. Shikany testified that NIPSCO proposes to recover the gross revenue amount of $1,482,166,740, which reflects a revenue increase of $46,608,036 as compared to test year pro forma results based on new service structure or a revenue decrease of $45,035,606 compared to test year pro forma results based on current rates, providing NIPSCO the opportunity to earn NOI of $271,211,585. She stated the agreed revenue requirement of $1,482,166,740 reflects a reduction of $63,648,449 from NIPSCO's case-in-chief proposal of $1,545,815,189 and a reduction of $62,891,513 from NIPSCO's rebuttal proposal of $1,545,058,253.

In summarizing the Step 1 revenue requirement, Ms. Shikany testified the Step 1 revenue requirement maintains the amortization of the unprotected property and other unprotected excess ADIT using ARAM and ten years, respectively and is based on the 12-month period ending June 30, 2019. Step 1 proposes to recover the gross revenue amount of $1,456,884,344, which reflects a revenue increase of $21,325,640 as compared to test year pro forma results based on new service structure or a revenue decrease of $70,318,002 compared to test year pro forma results based on current rates, providing NIPSCO the opportunity to earn NOI of $259,146,998.

Ms. Shikany explained the Revenue Settlement adjustments for Step 1. She testified that Settlement Adjustments OM 24-S2-S-19R, AMTZ 10-S2-S-19R, and AMTZ 11-S2-S-19R discussed above for Step 2 are applicable to Step 1. She testified the Step 1 revenue requirement is based on NIPSCO's current projections of utility plant in service, accumulated depreciation, and capital structure at June 30, 2019; therefore, the depreciation and some amortization expense adjustments, and the federal and state income taxes adjustment have been updated to include the pass back of the unprotected property and other unprotected excess ADIT at ARAM and ten years, respectively (the pass back of unprotected property and other unprotected excess ADIT at $12,170,384 per year, which will occur as of Step 2).

Ms. Shikany described the changes to NIPSCO's Tariffs as a result of the Revenue Settlement. She testified the Revenue Settling Parties agreed that: (1) NIPSCO will flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; and (2) NIPSCO shall discontinue its ECR Mechanism and shall recover the remaining regulatory asset over two years.

Ms. Shikany described the prospective annual credit mechanism agreed to in the Revenue Settlement. She stated the Revenue Settling Parties agreed that NIPSCO will implement an annual credit mechanism to reflect the difference between the net book value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base and rates resulting from the final order in this proceeding and the net book value at the date of the retirement as outlined in OUCC witness Blakely's direct testimony. She stated NIPSCO agreed to implement the credit upon the retirement of the generating units. She explained that the credit will be limited to the net book value of the Schahfer and Michigan City generating units embedded in base rates established in this Cause. She noted that NIPSCO will utilize a standardized form and will adjust: (1) the revenue requirement established in this proceeding; and (2) the NOI established in this revenue requirement for the purposes of its earnings test, and that NIPSCO agreed to hold annual pre-filing meetings preceding the 30-day filing with interested stakeholders.

Ms. Shikany testified that NIPSCO is seeking approval of depreciation accrual rates on an account by account basis. She stated that the depreciation study sponsored by Mr. Spanos in NIPSCO's case-in-chief, proposed specific depreciation rates by FERC account. She stated that the Revenue Settling Parties agreed that the depreciation accrual rates would be modified as described above to remove $26 million in contingency expense included in demolition costs and reflect the 2032 conclusion of the amortization period for the regulatory assets. Ms. Shikany stated that NIPSCO is requesting approval of these modified depreciation rates by FERC account.

Ms. Shikany explained that: (1) NIPSCO is seeking accounting authority to continue to defer, as a regulatory asset; discounts offered to certain customers under its Economic Development Rider for recovery in a future rate case in a manner consistent with the 44688 Rate Case Order; (2) NIPSCO is seeking authority to defer, as a regulatory liability, an amount equal to 100% of annual OSS margins net of expenses and back-up and maintenance demand margins, both for pass back through the RTO Tracker; and (3) NIPSCO is seeking authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. She testified that NIPSCO is requesting Commission approval of the deferrals.

C. NIPSCO Witness Westerhausen. Mr. Westerhausen explained how the Revenue Settlement rate-specific revenue requirement is calculated for proposed Rate 844 – Railroad Power Service, and he sponsored the proposed mitigation updated for the settlement revenue requirement and the adjustment for Rate 844. He also described and supported the Revenue Settling Parties' agreement that TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase.

Mr. Westerhausen testified that the Revenue Settling Parties agreed that Rate 844 shall see no increase in its base rates given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. He explained that keeping the demand rate at $16.85 and the two block energy rates at $0.041718 and $0.039468, resulted in the Rate 844

proposed mitigated revenue requirement excluding other revenue being $2,119,429 and that adding $26,855 in other revenue credits results in the proposed mitigated revenue for Rate 844 being $2,146,284. He explained that although the current Rate 744 two block energy rates are $0.041731 and $0.039481, these rates have been updated to reflect the forecasted rates to go into effect with the first billing cycle of October 2019 to adjust for the amortization roll off of the three-year amortization of electric vehicle expenses that was approved in the 44688 Rate Case Order.

Mr. Westerhausen testified that the Revenue Settling Parties agreed that TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. He stated this agreement is responsive to IMUG's testimony that the proposed Rate 850 rate increases to those municipalities that were the most prepared and first had their NIPSCO-owned street lights converted to LED would receive a disproportionate rate increase. He explained that NIPSCO recognizes and appreciates IMUG's concerns, and this agreement is responsive to those concerns. He testified that the Rate 850 settlement provision was very important to IMUG and necessary for their participation in the Revenue Settlement and that this adjustment only affects other customers within Rate 850. In Joint Exhibit 8, which was admitted in lieu of cross examination of Mr. Westerhausen, NIPSCO stated that the calculation of the cost of the Rate 850 agreement had been calculated on a monthly basis, but reported as an annual number. This resulted in an annual shortfall of revenue of $632,110. NIPSCO agreed with the OUCC to allocate only one-half of the revenue shortfall to NIPSCO's other Rate 850 customers and that NIPSCO would not seek recovery of the remainder from its other customers.

Mr. Westerhausen sponsored NIPSCO's proposed mitigation based on the Revenue Settlement's revenue requirement and the adjusted Rate 844 revenue requirement. He testified the total revenues proposed are based on an ACOSS that utilized a 4CP production allocation. He explained that with Rate 831 held at parity, the revised rate increase for all the rate classes except Rates 831 and 844 is 6.66%. Mr. Westerhausen also updated Attachment 19-R-F to his rebuttal testimony for the Revenue Settlement's revenue requirement and for the adjustment of Rate 844 in order to establish the allocation factors for NIPSCO's surviving tracking mechanisms.

D. OUCC Witness Blakley. Mr. Blakley's Revenue Settlement testimony addressed two items. He detailed the Revenue Settling Parties' agreement regarding the revenue credit mechanism related to the Schahfer and Michigan City Generating Stations. The revenue credit mechanism recognizes the net rate base value of the stations at the time the rates are approved in this Cause, then reduces the plant investment for annual depreciation at the time the first annual revenue credit mechanism is implemented. The mechanism will then recalculate NIPSCO's return on the reduced plant investment of Schahfer and Michigan City. He explained the difference between the return embedded in NIPSCO's base rates for Schahfer and Michigan City and the annual recalculated return based on the reduced plant value will be credited back to customers annually through a revenue credit mechanism filing.

Mr. Blakley also described the Revenue Settling Parties' agreement on excess ADIT to be returned to ratepayers. He described how the agreement will pass back approximately $203,164,460 of protected excess ADIT using ARAM over an estimated period of 26 years. Mr. Blakley also explained how the refund of unprotected and other excess ADIT of approximately $137,789,071 will start at $12,170,384 annually to begin after Phase 2 rate implementation on or

around March 1, 2020. At the time of NIPSCO's next rate case, the total amount of unprotected excess ADIT to be passed back will be determined and the agreed amortization may be adjusted.

Mr. Blakley testified these two portions of the Revenue Settlement generate customer benefits that were achieved only in settlement, as there was not consensus on either item in the parties' prefiled testimonies. He concluded that in context with the other terms, the entire Revenue Settlement serves the public interest and should be approved, in its entirety, without modification.

E. OUCC Witness Eckert. Mr. Eckert testified that if approved, the Revenue Settlement will provide certainty regarding critical issues, including revenue requirements, authorized return, and other miscellaneous issues. He testified that the Revenue Settlement was a result of intense negotiations with each party offering compromise to challenging issues, including assessing the litigation risk that the tribunal will find the other side's case more compelling. He stated that while the Revenue Settlement represents a balance of all interests, given the number of benefits provided to ratepayers, the OUCC believes the Revenue Settlement is a fair resolution, supported by evidence, and should be approved.

Mr. Eckert testified that as a result of the Revenue Settlement, NIPSCO's base rates reflect a lower revenue requirement than NIPSCO's initial proposal with the system-wide revenue increase of approximately 3.25%, thereby reducing the revenue increase impact for all NIPSCO's customers relative to NIPSCO's original proposal. He testified the Revenue Settlement resolves the TCJA issues and accounts for the changes to NIPSCO's revenue requirement necessary to address the TCJA and the Commission's order in Cause No. 45032-S5.

Mr. Eckert testified the ratepayer benefits in the Revenue Settlement include: (1) a $13.50 monthly residential customer charge – a $0.50 decrease from the current $14 charge and $3.50 less than NIPSCO's initial request of $17.00; (2) a 9.90% authorized ROE compared to NIPSCO's proposed increase to 10.80%; (3) resolving all issues regarding the TCJA; (4) NIPSCO's commitment to seek approval of a voluntary low-income program and establish a collaborative process to work out the program details (the cost of which is not reflected in the agreed revenue deficiency in this case); (5) certain exceptions to the depreciation accrual rates recommended by NIPSCO, resulting in a reduction to the revenue requirement; (6) adjustments to NIPSCO's proposed annual amortization expense; (7) an annual revenue credit mechanism reflecting the difference between the value of Schahfer and Michigan City units in NIPSCO's rate base at the time a final order is issued and the actual investment amount adjusted for depreciation; (8) changes to Rates and Tariffs; and (9) additional benefits negotiated by the Revenue Settlement.

Mr. Eckert explained that NIPSCO proposed a 10.80% ROE and the OUCC, Industrial Group, and other intervenors advocated for a considerably lower ROE applied to NIPSCO's original cost rate base. He testified that as a result of the negotiations, a compromise was reached, resulting in a 9.90% ROE and elimination of the fair value increment. Mr. Eckert testified a lower ROE benefits ratepayers by reducing the return on the rate base ultimately reducing the revenue requirement by approximately $23.8 million. He stated the Revenue Settlement establishes a balanced plan that is in the interest of both ratepayers and shareholders.

Mr. Eckert testified that the impacts of the TCJA lowered NIPSCO's annual revenue requirement by approximately $20.0 million as addressed in the Revenue Settlement. Mr. Eckert

also testified that the Revenue Settlement reduced test year O&M expense by $2 million, a reduction to amortization expense in the amount of $7,789,765, and a reduction in depreciation expense of $29 million.

With regard to treatment for OSS margins in the RTO Tracker, Mr. Eckert testified that flowing through 100% of OSS margins is an offset to ratepayers who are paying NIPSCO's retail rates to support the O&M expenses and provide a return of and a return on the assets that support OSS. He stated that ratepayers pay rates that reflect the MISO administrative fees, which provide for MISO to administer OSS of NIPSCO's excess generation. Additionally, 100% tracking of OSS margins will simplify the calculation of the OSS margin component of NIPSCO's proposed RTO Tracker and will provide transparency in the flow through of OSS margins. He testified that the Settling Parties agreement to continue NIPSCO's EDR proposal, including the deferral mechanism, will continue to bring economic benefits to NIPSCO, its ratepayers, and the region.

Mr. Eckert testified NIPSCO's commitment to seek approval of a voluntary low-income program within six months of an order in this proceeding. He stated that the program funding will be voluntary for all customers will not impact NIPSCO's revenue requirement.

Mr. Eckert concluded that the OUCC recommends that the Commission find the Revenue Settlement to be in the public interest and approve it in its entirety.

F. Industrial Group Witness Gorman. Mr. Gorman provided testimony in support of the Revenue Settlement and recommended that the Commission approve the settlement as reasonable and in the public interest.

Mr. Gorman testified that the Revenue Settlement reasonably resolved the parties' contested revenue issues. Specifically, he testified the Revenue Settlement reduced the proposed revenue increase by 57%, decreasing the proposed $111.4 million increase by $63.648 million. He testified that each of the revenue compromises, relative to the range of issues in the case, provide a reasonable outcome as they impact the total revenue requirement. He testified that the Revenue Settlement reflected a 9.90% ROE, which is in line with the ROE authorized by the Commission in NIPSCO's last base rate case. He added that the lack of change in capital market costs since that time supported finding a ROE reasonably comparable to the last case. Mr. Gorman also noted that NIPSCO had adjusted its proposed amortization of excess unprotected ADIT to ten years, and that the overall adjustment to operating expenses is appropriate and consistent with the compromise resolution of issues in the case.

22. Revenue Settlement Opposing Testimony.

A. ICC Witness Medine. Ms. Medine addressed three aspects of the Revenue Settlement: (1) approval years in advance of the accounting treatment and amortized recovery of undepreciated costs that NIPSCO will receive when it decides to retire any existing coal generation resource; and (2) any aspect of the settlement that locks-in specific retirement dates for any existing coal generation resource. In addition, she addressed why NIPSCO should only be allowed to include costs that are regularly adjusted outside base rates in the MISO bid prices for the coal units and should not be allowed to include costs that are recovered through base rates.

Mr. Medine recommended that the Commission deny approval of accounting treatment and amortized recovery that NIPSCO would receive if and when it retires any existing coal generation resources, and require NIPSCO to seek that relief at or near the time of actual retirement. She also recommended that the Commission avoid giving explicit or implicit approval to any specific date for retirement of any specific existing coal generation resource at this time. She recommended that the Commission limit NIPSCO from including variable operating costs in its offer price to MISO that are being recovered in base rates. Finally, she recommended that the Commission give guidance to NIPSCO for its 2021 IRP.

B. ICC/ICARE Witness Griffey. Mr. Griffey testified he does not oppose the Revenue Settling Parties' decision to set depreciation accrual rates for the coal units based on assumed lives ending in 2032. However, he recommended the Commission reject the aspect of the Revenue Settlement that would have it pre-approve now, years in advance of when NIPSCO may actually retire the units, regulatory asset treatment for sunk costs and pre-ordained amortization based on an assumption that the Schahfer units will all retire in 2023 and Michigan City in 2028.

Mr. Griffey noted a legislative Task Force will present findings in 2020 concerning the impacts of changing electric generation portfolios. He stated the Commission cannot know today what the statewide policies and regulatory statutes will be in 2023 and beyond thus making it premature to preordain in 2019 what accounting treatment and/or amortization treatment NIPSCO should receive if and when it actually retires existing generation resources in or after 2023.

Mr. Griffey stated that given the flaws in NIPSCO's IRP retirement and replacement analysis and the Task Force's mandate, he recommended the Commission: (1) decline to adopt any aspect of the settlement that forecloses flexibility; and (2) decline to approve explicitly or implicitly NIPSCO's professed retirement intentions based on its flawed IRP. He further recommended the Commission direct NIPSCO to: (1) perform an integrated retirement and replacement analysis in its 2021 IRP; and (2) seek regulatory and accounting treatment for any retiring coal plants at or near the time of actual retirement.

C. LaPorte Witness Cearley. Mr. Cearley took issue with the Revenue Settlement proposed cost of equity of 9.90% as being reasonable based on below average customer satisfaction results. He made two recommendations: (1) the Commission should adopt a return toward the bottom of the proposed range to reflect NIPSCO's lack of customer focus and poor customer satisfaction performance levels; and (2) NIPSCO's proposals to address its environmental and disproportionate level of large industrial load should have the effect of mitigating NIPSCO's risk. In response to the Commission's docket entry question, LaPorte stated that Mr. Cearley believes that a 25 to 50 basis point downward ROE adjustment for the elimination of each of these significant risk factors is appropriate and reasonable. LaPorte's docket entry response stated that this recommendation is further supported by Mr. Cearley's recognition in his direct testimony of the compounding effect of NIPSCO's repetitive risk adjustments to its return calculations based on environmental risks and its requests for upward risk adjustments due to a disproportionate level of large industrial load in its last three to four rate case proceedings.

23. Revenue Settlement Reply Testimony.

A. NIPSCO Witness Sistovaris. In response to LaPorte witness Cearley's criticism of NIPSCO's J.D. Power results and recommendation that the ROE in the Revenue Settlement be rejected, Ms. Sistovaris first noted that the J.D. Power surveys attached to his testimony do not support his claims. She explained that those surveys show on both the residential- and business- customer satisfaction side, NIPSCO's scores have been improving and that NIPSCO has been improving relative to its peers. Notably, NIPSCO is moving closer to the average survey result. She stated that on the residential side, NIPSCO has grown from a score of 645 in 2016 to a score of 706 in 2018 and that over that period, its distance from the average score has been cut in half. On the business side, NIPSCO's score has grown from 671 to 760, and it is almost at the average score. Additionally, J.D. Power has listed NIPSCO among the nation's most improved electric utilities in 2010, 2012, and 2015. She testified that these results show improvement, including improvement compared to NIPSCO's peers.

B. NIPSCO Witness Shikany. Ms. Shikany testified that Ms. Medine and Mr. Griffey seem to misunderstand the relief requested in this case. She explained this case is not about NIPSCO's preferred portfolio in its 2018 IRP, generation transition, or selecting a portfolio of resources. In fact, the preferred portfolio in the 2018 IRP is irrelevant to the issues in this case. She stated that this case is not about locking in retirement dates for NIPSCO's coal-fired generation. Rather, this is a general rate case, and as part of that general rate case, NIPSCO has sought approval of new depreciation accrual rates and has submitted a depreciation study. Ms. Shikany said that neither Ms. Medine nor Mr. Griffey took issue with the depreciation study or the depreciation rates that come out of the depreciation study. In fact, Ms. Medine specifically acknowledged that she takes no issue with the depreciation rate for NIPSCO's steam production plant, which underlies the Revenue Settlement. She stated that because the ICC and ICARE do not represent customers in this proceeding, the Revenue Settlement has no effect on them, and the only issue that may concern them (depreciation lives for coal plants), they explicitly accept.

Ms. Shikany testified that much of ICC and ICARE testimony is posturing for some future case that has not been filed rather than having anything to do with the relief NIPSCO seeks in this Cause. She noted that the ICC has intervened in four NIPSCO cases: this one, two PPA cases (Cause Nos. 45195 and 45196), and one joint venture case (Cause No. 45194). She explained that in all four cases, they have opposed NIPSCO's relief, yet none of those cases has any impact on the ICC, a fact that Ms. Medine admits when she notes that the "wind projects [in Cause Nos. 45195 and 45196] contribute very little UCAP and therefore have less relevance to the IRP which is focused on resources." Ms. Shikany stated that if those cases are irrelevant and have "very little impact" on the ICC's core issue (the IRP), then it is troublesome that the ICC chose to intervene and take up valuable resources to oppose relief "having very little impact." Instead, the ICC could have simply stated its issues with the IRP (which it has already done in the IRP process) and taken no issue on the ultimate relief sought – relief which every other party (all of whom represented actual customers who pay NIPSCO utility rates) agreed should be granted. She testified that this case contributes zero UCAP and therefore has even "less relevance to the IRP," and therefore less effect on the ICC and ICARE.

Ms. Shikany noted that both Ms. Medine and Mr. Griffey testified that NIPSCO's regulatory asset treatment resulting from the Revenue Settlement is unnecessary at this time and

should be deferred until the coal plants are actually retired. She stated the Revenue Settling Parties would not have reached a settlement that delayed the return on and of its investment in coal-fired generation until 2032 without granting the proposed regulatory asset treatment.

Ms. Shikany testified that deferring a decision on the regulatory asset treatment until the coal plants are actually retired would not be wise and is inconsistent with proper ratemaking. She described that this case is about establishing electric rates and, as part of that determination, setting new depreciation accrual rates. She explained that in the normal course, depreciation accrual rates would be set to recover the remaining book value over the remaining estimated useful life of the assets. She stated that the only evidence that has been introduced concerning the proper estimated useful life of the Schahfer units is 2023 and of the Michigan City unit is 2028. She testified that the ICC and ICARE have not proposed a different estimated useful life of these generating stations for depreciation purposes than that proposed by NIPSCO. She explained that under this scenario, NIPSCO would recover the remaining investment of Schahfer over the next four years and Michigan City over the next nine years at which point NIPSCO would fully recover its remaining investment in these units and would recover a return on that remaining investment. Ms. Shikany testified that from the outset of this case, NIPSCO has recognized that such a result would produce significant rate increases and has, accordingly, proposed to delay the recovery of the remaining investment over a longer period on the condition that the resulting regulatory asset would be included in rate base. She noted that every group representing customer interests in this case has either agreed to that condition or has not opposed it. She indicated that absent this condition, NIPSCO would recover the entire investment by the physical retirement date, which would result in significantly higher customer rates that would not be agreed to by the Revenue Settling Parties in the Revenue Settlement. She stated that the only parties opposing that condition are coal interests that will have absolutely no interest in whether NIPSCO earns a return of and on its investment.

Ms. Shikany stated that the only evidence that has been introduced of the estimated useful lives of NIPSCO's coal plants is 2023 and 2028. She explained that if NIPSCO were to come out of this case without either: (1) depreciation rates which would match recovery to those useful lives; or (2) assurance that it will recover both a return of and on any costs that would not have been recovered at the time of retirement, NIPSCO faces a risk of immediate write-off under GAAP, which would have a negative impact on the financial statements and the investor community. She also explained that a delay in the cash recovery beyond the useful life of the related assets without assurance that the remaining net book value of the coal generation assets as a regulatory asset in rate base could result in a negative impact on NIPSCO's credit ratings resulting in an increase in NIPSCO's cost of capital. She stated that not facing the depreciation issue today when it should be addressed would result in needless harm to an Indiana utility and its customers. Ms. Shikany testified there is a very real need to either set appropriate depreciation rates based upon the estimated useful life today or, if that result needs to be mitigated, assure NIPSCO that it will recover a return of and on its investment.

Ms. Shikany testified the deferral mechanism to which the parties have agreed provides that NIPSCO will recover a return of and on the investment through 2032. She explained that so long as those coal plants are retired between now and 2032, there would be absolutely no difference to the relief that is set forth in the Revenue Settlement. She explained that if Schahfer were to remain in service until 2028, the remaining net book value at the time of the retirement would be smaller (due to five years of additional depreciation expense) and NIPSCO would simply amortize

that remainder over a period shortened by five years. She noted that under either scenario, NIPSCO is recovering a return of and on the same investment and, therefore, there is no harm to customers from granting the regulatory asset treatment today.

In response to Ms. Medine's and Mr. Griffey's testimony that the Commission should wait to grant the regulatory asset treatment until after the legislative Task Force completes its work, Ms. Shikany stated that the legislative Task Force is not going to have an effect on the relief NIPSCO seeks in this proceeding and certainly no effect that could not be revisited at that time. Ms. Shikany stated that any number of changes could be implemented after they are adopted and would have no effect on this case. She said that as it is, there are no retirements planned until three years after the Task Force meets affording plenty of time to reflect legislative changes should they occur. She testified that the issue in this case is how much customers today should pay in rates so that NIPSCO can be assured recovery of a return of and on its investment in coal-fired generation that has served its customers very well for many years.

In response to Mr. Griffey's recommendation that the Commission should decline any aspect of the Revenue Settlement that forecloses flexibility and decline to approve explicitly or implicitly NIPSCO's retirement dates, Ms. Shikany testified that no aspect of the Revenue Settlement does either. She noted that there continues to be great flexibility for NIPSCO to adapt to the changing environment. She reiterated that this case is purely about cost recovery today, and the Commission is not approving explicitly or implicitly retirement dates; rather, it is setting depreciation accrual rates. She stated that the actual lives of these generating facilities may be different than the lives that are estimated today, which is not uncommon. She testified that if estimated lives change, the differences will be addressed through prospective changes in depreciation accrual rates that would be proposed in a subsequent base rate proceeding.

C. NIPSCO Witness Augustine. Mr. Augustine responded to Mr. Griffey and Ms. Medine's claims that NIPSCO's 2018 IRP contained multiple flaws. Mr. Augustine sponsored his rebuttal testimonies in Cause No. 45194 (Attachment 6-S1-R-A), 45195 (Attachment 6-S1-R-B), 45196 (Attachment 6-S1-R-C), and NIPSCO's response to stakeholder comments on the 2018 IRP (Attachment 6-S1-R-D) and testified that within his rebuttal testimony in this Cause and in these other responses and testimonies, he addressed concerns related to industrial load uncertainty, end effects calculations, and the 20-year versus 30-year analysis time horizon, retirement, and replacement analysis modeling and associated portfolio development assumptions, future coal plant capital and maintenance costs, environmental regulation assumptions, scenario development and the IRP's stochastic risk analysis, the flexibility of NIPSCO's preferred portfolio, wind and solar cost and operational assumptions, congestion and transmission cost assumptions, and ancillary services cost assumptions. He noted that many of the concerns raised by witnesses Griffey and Medine related to NIPSCO's 2018 IRP in their responses to the Revenue Settlement were litigated in significant detail in Cause Nos. 45195 and 45196, wherein the Commission concluded that "[w]hile ICC criticized various aspects of NIPSCO's modeling, witness Augustine, in rebuttal, adequately addressed those criticisms."[36]

[36] Order in Cause No. 45195 (IURC 06/05/2019) (the "45195 Order"), p. 9, and Order in Cause No. 45196 (IURC 06/05/2019) (the "45196 Order"), p. 10.

Mr. Augustine responded further to Mr. Griffey's claims that NIPSCO's two-step retirement and replacement analysis is inherently flawed and, Ms. Medine's suggestion that the Commission should direct NIPSCO to perform integrated planning that does not separate retirement and replacement decisions. He testified that the IRP analysis approach allowed NIPSCO to first fully evaluate a wide range of retirement concepts and then to secondly evaluate replacement portfolios across a range of objectives and a range of commitment duration and diversity outcomes. He testified that in its 45195 and 45196 Orders, the Commission affirmed its understanding of this process, and in response to the ICC's claims that the approach was biased, stated that the "ICC fails to recognize that the two analyses have distinct purposes."[37] He noted that the first purpose of evaluating the range of retirement options is most relevant because the issue at hand is the economic useful life of the current coal fleet and the depreciation rates for NIPSCO's existing assets, and not a specific replacement decision. He explained that throughout its 2018 IRP, NIPSCO found that the early retirement of coal capacity is cost effective for customers whether the existing coal units are replaced with the least cost renewable options from the RFPs conducted as part of the 2018 IRP or with higher-cost MISO market energy purchases and capacity costs based on cost of new entry. He stated Mr. Griffey has not refuted this, and his efforts to compare retirement portfolios from this first step of the analysis with replacement portfolios that were constructed based on different objectives in the second step should not distract from the clear finding that retaining coal is higher cost than any number of alternatives. He stated again that NIPSCO incorporated other decision metrics in its analysis, including cost risk, reliability risk, environmental stewardship, and the impact on employees and the local economy in arriving at its preferred portfolio. He stated that if NIPSCO followed Mr. Griffey's guidance to select the lowest cost portfolio over the next 20 years, then a portfolio that retires all coal in 2023 would have been chosen. He testified that instead, a plan that staggers the retirements and replaces capacity with a mix of different renewables with different commitment durations was selected.

Mr. Augustine responded to Mr. Griffey and Ms. Medine's suggestion that industrial load uncertainty, particularly related to proposed Rate 831, was not sufficiently addressed in the 2018 IRP. He testified that: (1) NIPSCO's 2018 IRP evaluated a low load scenario with substantial industrial load leaving the system; (2) the competitiveness of the existing coal fleet and alternative replacement renewable resources is driven primarily by the cost structure of such resources and their position in the MISO market and not NIPSCO's internal load; and (3) future loss of firm load can be managed through the flexibility inherent in NIPSCO's preferred portfolio. He added that he is now aware that the partial settlement with five large industrial customers in this Cause is based on subscription of approximately 194 MW of firm load to Rate 831. He stated that when offset by the loss of industrial interruptible capacity that NIPSCO currently considers a supply resource, the impact of this rate design change on NIPSCO's load obligations is approximately 60 MW, a level that is far less than the load uncertainty ranges evaluated in the IRP and represents a small fraction of total demand.

Mr. Augustine responded to Mr. Griffey's testimony that the commitment of less than 200 MW for Tier 1 service is only for five years, which should support a decision to maintain flexibility about when to retire the coal plants, and Ms. Medine's suggestion that in the future NIPSCO should use a load forecast that accounts for any possible resulting change in load both in the initial five years of Rate 831 contracts and in later years. He agreed that load uncertainty should continue to

[37] 45195 Order, p. 9, 45196 Order, p. 10.

be evaluated and that the industrial load uncertainty in NIPSCO's service territory is one reason to ensure flexibility in the supply portfolio; however, he testified that NIPSCO's preferred portfolio accomplishes this far better than Mr. Griffey's preference to continue operating the coal plants. He demonstrated that continued operation of the coal fleet is immediately higher cost than the alternatives, while NIPSCO's replacement plan allows for flexible procurement of new resources with different commitment durations over time, all at a lower cost. He stated that Mr. Griffey falsely attempts to claim that lower industrial load in the Challenged Economy scenario was the reason why coal units looked more economic, when the real driver of this result was the lack of a carbon price in that scenario. He stated that all of the scenarios evaluated by NIPSCO in the 2018 IRP, including the one designed by the ICC, showed that early retirement of the coal plants results in lower customer costs.

Finally, Mr. Augustine testified that he does not believe that Mr. Griffey's attempts to compare NIPSCO's process and situation to Vectren's are valid. In response to his claims that like Vectren, "NIPSCO plans to put most of its eggs in [one] basket," Mr. Augustine asserted that this is not true at all. NIPSCO plans to phase out coal plants over a ten-year period, NIPSCO owns an approximately 500 MW existing natural gas combined cycle plant that is part of its long-term preferred portfolio, along with other smaller natural gas peaking units, and NIPSCO plans to procure a mix of owned and contracted wind, solar, and storage resources, allowing for significant diversity and flexibility in resource procurement as technology and markets evolve. He noted that the Commission recently acknowledged the distinction between Vectren's plan and NIPSCO's and affirmed that "NIPSCO's 2018 IRP was explicitly developed to maintain optionality to enable making adjustments and modifications as circumstances warrant."[38]

Mr. Augustine also testified that Mr. Griffey's claim that "NIPSCO's IRP ignored options that could allow the coal units to remain in service" is false, as NIPSCO explicitly developed a range of portfolios that keep coal plants on longer, including with less stringent environmental regulations. He explained that NIPSCO also evaluated a scenario developed by the ICC that assumed *no* additional environmental capital expenditures would be required for the coal fleet and still found that early retirements were lower cost. Additionally, NIPSCO evaluated coal-to-gas conversion options and found that renewable replacements were lower cost than conversion. He stated that Mr. Griffey's claims that NIPSCO "failed to consider the possibility of higher gas and energy prices without CO2 taxes" and failed to update assumptions related to load uncertainty and wind operational parameters are false. He testified that NIPSCO evaluated a scenario with higher gas and energy prices and no CO2 price, designed specifically by the ICC to test the possibility Mr. Griffey claims was ignored, and found that early coal retirement and replacement with renewables was lower cost. In addition, NIPSCO also addressed load uncertainty sufficiently and confirmed that the overall cost and performance of the specific wind resources currently being added to the portfolio are consistent with the IRP's assumptions for wind resources.

D. NIPSCO Witness Campbell. Mr. Campbell responded to Ms. Medine's request that NIPSCO exclude non-FAC costs for purposes of MISO offer prices for NIPSCO's coal units. He testified that this issue was raised and rejected by the Commission in its April 29, 2019 Order in Cause No. 38706 FAC 122. He stated that in that Order, the Commission found that

[38] Order in Cause No. 45195 (IURC 06/05/2019) (the "45195 Order"), p. 10, and Order in Cause No. 45196 (IURC 06/05/2019) (the "45196 Order"), p. 11.

NIPSCO demonstrated that its current offer strategy of its generation units into the MISO energy market was reasonable.[39] In addition, NIPSCO did not include inappropriate components of its offers to MISO, nor were they imprudent with respect to its generation decision-making. As such, the Commission should reach the same conclusion in this case. Mr. Campbell testified that Ms. Medine's view that including costs that are not tracked in NIPSCO's FAC would result in the possibility of over recovery of costs would actually result in an under recovery of costs related to the sale of energy into the MISO market. He explained that the variable costs of production that are built into the agreed revenue requirement are based upon production cost modeling, which is based upon NIPSCO's variable costs of production in relation to other sources of power offered into the MISO market. He stated that if NIPSCO were not to include all of the variable costs of production in its actual bids, all else being equal, NIPSCO's units would dispatch more energy than is assumed in the rate case. In other words, NIPSCO would incur variable costs of production that are not tracked and that would be in excess of the amount assumed in this case.

Mr. Campbell testified that even if the Commission allowed NIPSCO to recover its higher projected variable costs in base rates, NIPSCO's retail customers would be harmed. He explained that MISO maximizes the efficient use of the energy grid by utilizing its Security Constrained Economic Dispatch software that matches energy needs with resources based upon capability and price. He stated that were NIPSCO to offer its generation into the MISO market without consideration of its related variable costs, its offer price would not reflect the economic cost of running its generation units, its generating units would be uneconomically dispatched, and its retail customers would likely end up paying higher costs.

24. Overview of the Rate 831 Settlement. On May 17, 2019, NIPSCO, Industrial Group, NLMK Indiana, and US Steel filed the Rate 831 Settlement.[40] The Rate 831 Settling Parties stated that the Rate 831 Settlement fairly and reasonably resolves issues related to Rate 831, subject to Commission approval without any modification or condition that is unacceptable to the Rate 831 Settling Parties. The Rate 831 Settlement looks to resolve all issues related to implementation of Rate 831. The key terms of the Rate 831 Settlement are summarized as follows:

- The Rate 831 Settling Parties[41] agree that NIPSCO's COSS should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 MW.[42] The Rate 831 Settling Parties agree that $149.438 million (exclusive of approximately $2.827 million in "other revenues") shall be allocated to Rate 831.

- For purposes of tracker allocations, the Rate 831 Settling Parties agreed:

    - Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO witness Westerhausen's Verified Rebuttal Testimony

[39] The Commission stated (at 9) that "NIPSCO has adequately demonstrated that it 'has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]' Ind. Code § 8-1-2-42."

[40] The Rate 831 Settling Parties filed a revision to the Rate 831 Settlement on June 7, 2019.

[41] US Steel filed testimony only related to Rate 831, and thus supports the settlement COSS as it relates to the rates, charges, and trackers related to Rate 831, and takes no position on the remaining rate design.

[42] As shown in Confidential Exhibit C to the Rate 831 Settlement, Tier 1 subscriptions will be less than the presumed MW level, but this shall not alter the stated revenues assigned to Rate 831.

(updated for the settlement revenue requirement and the adjustment for Rate 844), shall be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms;

- Rate 831 Implementation Agreement Exhibit B, which is Attachment 19-R-E to NIPSCO witness Westerhausen's Verified Rebuttal Testimony (with no changes), sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism; and
- For the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO witness Westerhausen's Verified Rebuttal Testimony (updated with the settlement revenue requirement), reflect the allocation factors for TDSIC purposes.

- For purposes of Rate 831 rate design, the Rate 831 Settling Parties agreed:
  - Except as otherwise provided in the Rate 831 Settlement, the Rate 831 Settling Parties agree that Rate 831 shall be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in Paragraph B.1. of the Rate 831 Settlement.
  - The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the COSS presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in Paragraph B.1. of the Rate 831 Settlement.
  - For purposes of the AAQFPTC, the Rate 831 Settling Parties agree that the provision shall be amended by adding the following language: "If the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period."
  - The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial five-year contract is set forth in Rate 831 Implementation Agreement Confidential Exhibit C. The Rate 831 Settling Parties agree that Tier 1 subscriptions reflected in Rate 831 Implementation Agreement Confidential Exhibit C shall be binding upon each customer in the event of the approval of this Agreement without modification.
  - The Rate 831 Settling Parties agree that a transition period, lasting from the date on which Step 1 Rates become effective until June 1, 2020, shall provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and capacity needs. The Rate 831 Settling Parties agree that

the terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

25. Rate 831 Settlement Supporting Testimony.

A. NIPSCO Witness Westerhausen. Mr. Westerhausen summarized the Rate 831 Settlement. He testified that the Rate 831 Settlement reflects the Rate 831 Settling Parties agreement on issues related to Rate 831 between and among themselves, including implementation. He stated the specific objectives addressed in the Rate 831 Settlement include resolution of: (1) the allocation of costs to Rate 831, eliminating the risk for a Phase 2 proceeding provided the Revenue Settlement, revenue allocation, and rate design of Rate 831 as proposed by NIPSCO are accepted; (2) allocation of trackers; and (3) Rate 831 implementation.

Mr. Westerhausen summarized that for purposes of settlement, the Rate 831 Settling Parties agreed that NIPSCO's COSS should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 MW allocating approximately $149.438 million (exclusive of approximately $2.827 million in "other revenues") to Rate 831.

Mr. Westerhausen stated that for purposes of settlement, the Rate 831 Settling Parties agree: (1) that Rate 831 Implementation Agreement Exhibit A (which is Attachment 19-R-F to his rebuttal testimony updated for the settlement revenue requirement and the adjustment for Rate 844) will be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms; (2) that Rate 831 Implementation Agreement Exhibit B (which is Attachment 19-R-E to his rebuttal testimony with no changes) sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism; and (3) for the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load," and TDSIC revenue allocation will only be applied to revenue associated with Rate 831 customers' Tier 1 load. He stated the Rate 831 Settling Parties agreed that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A reflect the allocation factors for TDSIC purposes.

Mr. Westerhausen summarized that for purposes of settlement, the Rate 831 Settling Parties agree that: (1) except as otherwise provided in the Rate 831 Settlement, Rate 831 will be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in the Rate 831 Settlement; (2) the design of Rate 831 will be based on the COSS presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in the Rate 831 Settlement; (3) the "Adjacent Affiliate Qualified Facility Premise Transmission Charge" provision will be amended to be clear that if the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period; (4) the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial five-year contract is as set forth in Rate 831 Implementation Agreement Confidential Exhibit C and agree that Tier 1 subscriptions reflected in Rate 831 Implementation Agreement Confidential Exhibit C will be binding upon each customer in the event of the approval of the Rate 831 Settlement without modification; and (5) a transition period (lasting from the date on which Phase I rates become effective until June 1, 2020) will provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and

capacity needs and agree that applicable terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

Mr. Westerhausen testified that Rate 831 Implementation Agreement Exhibit D sets forth the: (1) Tier 2 and/or Tier 3 contract terms; (2) rate implementation dates; (3) firm capacity transactions under Tiers 2 and 3; and (4) dispute resolution provisions, applicable to the transition period. He stated that the Rate 831 Settling Parties agree that any contract for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions: (1) identify NIPSCO as the Market Participant for the retail customer at MISO; (2) reference NIPSCO's market-based rate authority with FERC; (3) clearly state the Rate 831 customer remains a retail customer of NIPSCO; (4) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations); (5) incorporate relevant provisions of the Rate 831 tariff; (6) all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and (7) any information shared with NIPSCO shall be subject to a confidentiality agreement applicable to all terms of said agreements.

Mr. Westerhausen testified that the Rate 831 Settling Parties agree that the customer's elections under Rate 831 Tiers 2 and/or Tier 3 will occur in a window between the day after NIPSCO's compliance filing in this Cause to 30 days thereafter. He explained that in discussions with NIPSCO, customers recognize that in order to implement Tier 3, customers may need to install software including a security certificate provided by NIPSCO. He noted that the parties agree to work together during the 30-day period to achieve implementation.

Mr. Westerhausen testified that NIPSCO agrees that under either Tier 2 or Tier 3, a customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges.

Mr. Westerhausen testified that NIPSCO agrees that the third-party energy and capacity supplier may represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the Commission. He indicated that at a minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.

Mr. Westerhausen sponsored a redlined tariff that incorporates changes necessary to implement the Rate 831 Settlement as Attachment 19-S2-A.

Mr. Westerhausen testified that if approved, the Rate 831 Settlement assures that if the agreed-upon revenue requirement (as reflected in the Revenue Settlement) and NIPSCO's proposed Rate 831 and cost allocation are approved, there will be no need for a Phase 2 proceeding to establish revised rates. Additionally, Rate 831 Implementation Agreement Exhibit D specifically addresses implementation concerns previously raised by some industrial customers.

B. Industrial Group Witness Phillips. Mr. Phillips presented testimony in support of the 831 Settlement among NIPSCO, the Industrial Group, NLMK, and US Steel. Mr.

Phillips explained that members of the Industrial Group, particularly ArcelorMittal, BP, Cargill, and Praxair, are among the largest of NIPSCO's industrial customers and not only qualify for, but are willing to accept the risk associated with using the proposed service structure under Rate 831.

Mr. Phillips reiterated the importance of establishing appropriate industrial rates as these energy intensive industries continue to face intense domestic and international competition. He stated because of the energy intensive nature of their businesses, energy costs are a major component of the companies' production cost and materially impact economic viability of their operations in NIPSCO's service territory. He stated that approval of the Rate 831 service structure in a form that effectively addresses the issues the rate was intended to address is of significant importance to the Industrial Group. He noted that given the importance of keeping and attracting industrial customers to the overall economic benefit of northwest Indiana, approval of Rate 831 should be of significant importance to all participants in the rate proceeding.

Mr. Phillips testified that the Industrial Group shares the interest in mitigating the rate increases for all customers and therefore was an active and aggressive participant in the negotiations that led to the Revenue Settlement. He noted that settlement reduced NIPSCO's proposed revenue requirement by approximately $63.6 million, which significantly reduced the overall rate increase for all customers.

Mr. Phillips explained that the Rate 831 issues covered in the Implementation Agreement reflect changes in the revenue requirement established by the Revenue Settlement. He added that the Implementation Agreement resolved contested issues regarding the design of Rate 831 and includes the commitment of each Rate 831 customer to take an agreed level of firm service under Tier 1. He added that although the actual level of Tier 1 demand subscribed to by the Rate 831 customers is less than the 194.556 MW that NIPSCO used to allocate cost to Rate 831, the Implementation Agreement provides that the allocation of cost will continue to be based on 194.556 MW. He noted the result of that provision means that the actual rates for Rate 831 will be above cost of service for those customers. Mr. Phillips said that the Implementation Agreement also provides tariff revisions to reflect modifications NIPSCO made on rebuttal or to resolve other issues raised by Rate 831 customers, such as a dispute resolution process, implementation of aggregated metering for adjacent premises, and formulating requirements for third-party contracts.

Mr. Phillips concluded that he recommends approval of the Implementation Agreement because, in his opinion, it significantly reduces the range of issues that would need to be resolved regarding Rate 831, which reduces the need for further litigation on those issues and eliminates the need for a Step 2 true-up process. He concluded the Implementation Agreement establishes Rate 831 in a manner that is workable and fulfills the goals that it was introduced to address.

C. US Steel Witness Georgis. Mr. Georgis testified in support of both the Revenue Requirement and Rate 831 Settlements, noting specifically that the Rate 831 Settlement is premised on the 4CP allocation of production costs because it is appropriate for NIPSCO's summer peaking system and because a 12CP methodology will shift costs into the Rate 831 industrial class, thereby creating even stronger economic signals that make customer self-generation more attractive. Mr. Georgis stated that US Steel's decision to enter into the Rate 831 Settlement is driven by US Steel's analyses of its least cost power options and is an acceptable alternative to NIPSCO's status quo rate structure, which is no longer an economically viable option

for US Steel. Mr. Georgis provided specific details on US Steel's plans to self-build new cogeneration if an economic solution is not achieved.

Mr. Georgis observed that if Rate 831 is not approved or is modified to include additional cost shifts or transition fees, it will be uneconomic for US Steel compared to its cogeneration self-build option. Mr. Georgis testified that in the Rate 831 Settlement, the large industrial customers proactively agreed to commit to a set amount of Tier 1 firm contract demand that fully recovers the required settled revenue requirement for Rate 831 and without such a commitment, the Revenue Settlement as it relates to Rate 831 is meaningless because no customer can be forced to take a set level of firm demand. Mr. Georgis concluded that in addition to being the most economic option for US Steel, the Rate 831 Settlement guarantees that US Steel will remain a customer taking service with a firm contract demand, thereby improving the certainty and future stability of NIPSCO's revenues and rates while US Steel continues to contribute to NIPSCO's fixed cost recovery to the benefit of all customers.

26. Rate 831 Settlement Opposing Testimony.

A. OUCC Witness Boerger. Dr. Boerger filed testimony is response to the Rate 831 Settlement. He supported the OUCC's position that the Rate 831 Settlement should be rejected because it does not address the problems with NIPSCO's original Rate 831 proposal. Dr. Boerger stated that the Rate 831 Settlement does not address, even in part, the cost shift from Rate 831 customers to other rate classes that he identified in his direct testimony. Dr. Boerger addressed the supposed historical "sizable subsidy" argument presented in the Rate 831 Settlement, which appeared to be the basis for not addressing the cost shift to other rate classes. He noted that these large customers cost more to serve than is reflected in traditional cost of service studies, calling into question the existence of such historical subsidies.

Additionally, Dr. Boerger identified other issues of fairness that the Rate 831 Settlement does not adequately address, including the use of a 4CP cost allocation methodology that the Commission has not previously approved for NIPSCO that would further shift costs away from Rate 831 customers. Further, the Rate 831 Settlement, according to Dr. Boerger, would have the Commission accept changes to the AAQFPTC which would cause it to no longer reflect the cost of providing this service, providing further reason to reject the Rate 831 Settlement. Dr. Boerger also stated that the Rate 831 Settlement would not allow the Commission to redesign NIPSCO's proposed transmission charge in a way that would provide correct economic signals for the building of self-generation facilities, as discussed in his direct testimony.

Finally, Dr. Boerger identified an issue discovered in reviewing Rate 831 Settlement documents that carries over from NIPSCO's original proposal for calculating its demand-related cost allocation tracker factors (shown originally in NIPSCO witness Westerhausen's Attachment 19-E). NIPSCO and other settling parties would have a TDSIC-like reduction in cost responsibility applied to non-firm load in spite of a lack of evidence or statutory requirement for making this change, as is the case with TDSIC trackers. Dr. Boerger concluded that this proposed allocation methodology would result in Rate 831 customers being allocated too little revenue requirement and other rate classes too much revenue requirement, and he recommended that NIPSCO be required to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1

Adjustment shown in Implementation Agreement Exhibit A and in Attachment 19-E of Mr. Westerhausen's prefiled direct testimony.

B. CAC Witness Olson. Mr. Olson offered testimony in response to the Rate 831 Settlement. He sponsored transcripts from the public field hearing, highlighting testimony from many of the speakers, including the Michigan City Council President, local business owners, and residential customers. He spoke about several local ordinances and resolutions passed by municipal governments located in NIPSCO's service territory, which reference the initial request for an approximate 12% increase for residential customers. Mr. Olson stated that all members of the rate-paying public have an interest in achieving a fair and balanced outcome, but the parties to the 831 Settlement are its only beneficiaries. Mr. Olson concluded that the Commission should reject NIPSCO's proposal for industrial restructuring and reject the proposed Rate 831 Settlement.

C. CAC Witness Wallach. Mr. Wallach testified the Rate 831 Settlement would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes and would allocate those costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand, not contract demand. He stated that the proposed allocation of revenues to the Rate 831 class would recover from large industrial customers less than their fair share of embedded production costs and would instead unfairly and unreasonably shift recovery of such costs to other rate classes. Specifically, he estimated that the Rate 831 Settlement's revenue allocation would shift recovery of about $66 million of annual non-fuel revenue requirements from industrial customers to other customers, assuming a 4CP allocator is used. If demand-related production costs were allocated using a 12CP allocator, as the OUCC recommends, then Mr. Wallach estimated the proposed Rate 831 Settlement would shift recovery of about $94 million of annual non-fuel revenue requirements from industrial customers to other customers.

Mr. Wallach recommended the Commission reject the Rate 831 Settlement and deny NIPSCO's request for an ARP as not in the public interest. Instead, he recommended that the current industrial service structure be retained and that a procedural schedule be established to determine the appropriate revenue allocation and rate design for all rate classes.

Mr. Wallach testified there is a risk of a loss of industrial load, with its attendant cost-shifting, if the Commission decides to retain the current industrial service structure; however, neither NIPSCO nor any of the other Rate 831 Settling Parties provided any evidence that the potential load loss under the current service structure would exceed the current load loss under the proposed Rate 831 structure. Thus, he said, the Rate 831 Settling Parties failed to show that other customers would be worse off under the current service structure than under the Rate 831 structure. Instead, the Rate 831 Settling Parties would have the Commission approve a radical change in the industrial service structure based on speculation that the potential margin loss with the current structure could be even greater than the demonstrated loss under the Rate 831 structure.

27. Rate 831 Settlement Reply Testimony.

A. NIPSCO Witness Kelly. Mr. Kelly made clear that in the event the Commission rejects the Rate 831 Settlement, as suggested by both OUCC witness Boerger and CAC witness Wallach, the revenue requirement would need to be changed to remove adjustments

that were made to effectuate the ARP, including updating load research for historical demand to reflect firm demand for Rate 831 customers under existing Rates 732, 733, and 734; addressing the treatment of MISO charges and revenues that have been proposed to be removed from base rates; making adjustments to reflect aggregation that would migrate customer premises among Rates 724, 732, and 733; and addressing Rider 776 Back-up, Maintenance, and Temporary Service revenues and OSS activities.

Mr. Kelly also noted that the assumption that US Steel's demand under Rates 732 and 733 would be similar to that projected under Rate 831 is incorrect because no additional interruptible service is available under Rider 775. As such, the firm amount would need to remain at a level consistent with today's 700 Series rate structure, under Rate 831, except for the adjustment for aggregating multiple premises currently served under Rates 732 and 733.

Mr. Kelly pointed out that no evidence has been provided to show that an across-the-board rate increase as suggested by OUCC witness Boerger utilizing existing Rates 732, 733, and 734, would result in rates that were just and reasonable.

Mr. Kelly raised concern that the testimony of witnesses Boerger, Wallach, and Olson (and others) attacks the prudence of Rate 831 by fixating on the near-term impacts to other rate classes without recognizing the substantial long-term risks that are in play with this decision. He testified that what is being characterized as an industrial subsidy for Rate 831 customers is a misnomer and ignores the fact that Rate 831 is a fully costed rate designed at parity. He emphasized that NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers as it addresses its aging coal generation fleet and navigates a dynamic economic environment. Mr. Kelly opined that it is undeniable that the Rate 831 proposal will assign more of NIPSCO's production costs to other customer classes, which will produce higher rates in the near term than they would otherwise pay absent the restructuring of large industrial rates. He asserted that the long-term risk is garnering little attention and that these large industrial customers already have options for significantly reducing their firm requirements and are poising themselves to implement those options if Rate 831 is not approved.

Mr. Kelly testified that if Rate 831 is not approved according to the terms of the Rate 831 Settlement, he is convinced that at least some of these customers are going to make the incremental investments to leave the NIPSCO system, or worse, will shift industrial production away from NIPSCO's service territory. He stated that when that occurs, NIPSCO will need to file multiple rate cases as chunks of firm load leave its system, and those rate cases are going to propose to reallocate the unrecovered fixed costs left behind by these customers from the remaining customer classes. He testified that while witnesses in this case are focusing on the fairness of a cost shift within this rate case of approximately $40 million to $66 million between Rate 831 and other classes, if NIPSCO does not move to the Rate 831 structure now, it will be talking about another $100 million to $150 million of unrecovered costs that would have been collected under Rate 831 but will be left behind as these customers further bypass NIPSCO's service. That is not to say that $40 to $66 million dollars is an insignificant issue or that NIPSCO does not care about the near-term impact to its other customers classes, but when NIPSCO considered the full range of impacts in play rather than just the near-term cost shift, it was apparent that Rate 831 is the right solution now rather than later. Mr. Kelly restated that attempting to retain the current service structure is

only going to increase the risk that these customers will exercise their options to cogenerate additional power or relocate production to avoid an increasing NIPSCO electric price.

Mr. Kelly stated that he is concerned because the arguments being raised attempt to mute NIPSCO's interest in representing its other customer classes in the Rate 831 proposal. He noted that it is atypical for a vertically integrated utility to propose allowing a significant portion of its load to have the ability to procure capacity and energy from wholesale market suppliers; in fact, that cuts directly against the profit motive of an investor-owned utility. He asserted that NIPSCO is considering the interest of all of its customers and stakeholders as it moves through this transitional time.

Mr. Kelly testified that the Rate 831 proposal would reduce NIPSCO's long-term business opportunity as an investor-owned utility because it is downsizing the amount of firm load that NIPSCO is obligated to serve for at least five years thereby reducing the amount of MW that NIPSCO has the right under Indiana law to serve under its monopoly charter. He stated that the reason NIPSCO is making this proposal, however, is because it is the best outcome that could be identified for all of its customers, employees, investors, and stakeholders given the parameters that NIPSCO faces at this time of sustained low natural gas prices, historically lower cost of capital, aged coal-fired generation, aging boiler systems within customer plants creating a cogeneration opportunity when replacing, large sophisticated energy users, strong economic conditions, etc. Mr. Kelly testified that this decision was not reached lightly, and NIPSCO did not craft it alone for its benefit. His ultimate concern is that NIPSCO is going to miss out on reaching a sustainable path forward where these customers keep paying a sizeable portion of their costs because there is a lot of volume on the near-term portion of the analysis without considering the substantially larger risk around the long-term portions.

In response to CAC witness Olson's testimony objecting to a 12% rate increase for those other rate classes, Mr. Kelly pointed out that the 12% figure is the result from NIPSCO's original proposal as filed. He pointed out that if the Commission approves both the Rate 831 Settlement and the Revenue Settlement, the resulting change in rates for all other customers (other than Rate 831) would be 6.66%.

Finally, Mr. Kelly pointed out the consequences of rejecting the Rate 831 Settlement. He explained that as NIPSCO begins to implement the results of its IRP and procure replacement capacity that will live on for decades, NIPSCO needs to ensure some stability in what its obligation to serve will be for its largest industrial loads. He stated that retaining the current industrial service structure will only increase the risk that NIPSCO's industrial load will further decline over time and create unrecovered costs on the way down. Mr. Kelly testified that without approval of the Rate 831 industrial service structure, NIPSCO would be put into a position of modifying its existing Rate 732, 733, and 734 service structure to re-integrate the Rate 831 customers, which is no small task. He explained that as part of that process, to retain some of the assurances of stability in the near term, NIPSCO would likely seek to modify parts of the existing Rate 732, 733, and 734 industrial service structure such as changing contract terms, altering Rider 775 registrations, and restructuring NIPSCO's back-up and maintenance service. He noted that these steps do not actually reduce the risk industrial customers will exercise their options in the future, and may in fact increase that chance.

B. Industrial Group Witness Phillips. Mr. Phillips presented settlement reply testimony in response to the OUCC witness Boerger and CAC witness Wallach. In response to the OUCC and CAC witnesses' assertion that the Implementation Agreement unfairly shifts rate recovery of NIPSCO's legacy production costs to other customer classes, Mr. Phillips testified that for many decades the industrial classes have paid above-cost rates in order to subsidize residential customers. Mr. Phillips discussed the Commission orders describing the inter-class subsidies that industrial classes have provided to other customers. Mr. Phillips also stated that over the last two rate cases, industrial rate increases have totaled more than 22%. Mr. Phillips quantified the magnitude of the rate subsidies paid over the years by the industrial classes as being in the range of $1.4 billion to $2.85 billion, which are substantially greater than the legacy cost that Dr. Boerger and Mr. Wallace contend the large industrials would avoid under the Implementation Agreement. He stated that it is clear that the industrial classes have already provided rate revenue far in excess of their cost-based share of NIPSCO's legacy production cost and that essentially the OUCC and CAC are advocating for continuing and increasing the subsidies paid by industrial customers.

Mr. Phillips took issue with Dr. Boerger's theory that a need for rate mitigation does not necessarily imply the presence of a subsidy and that industrial customers should have paid higher returns in the past. Mr. Phillips first noted that it is clear residential customers have been subsidized for a number of years as detailed in Commission orders as far back as 1981. Mr. Phillips also noted that in the current case, even under the OUCC's preferred cost methodologies, the residential class would still be receiving a subsidy. He added that if all subsidies were eliminated and a 12CP allocation method were used, the residential class would see a rate increase of 17.4% rather than the 6.66% provided for in the Revenue Settlement agreement and the Implementation Agreement. He stated that questioning the residential rate subsidy amounts to disagreeing with both a consistent line of Commission orders and the OUCC's own cost of service proposal.

Mr. Phillips also testified that Dr. Boerger's theory that industrial customers should have been paying a higher rate of return had never been addressed in NIPSCO's past rate cases or in any of the cost allocation methodologies the OUCC has proposed. He added that the alleged risk suggests volatility in the industrial load in contrast to what Dr. Boerger described as the more stable residential service, but in fact the residential load is much more volatile due to seasonal swings than the high load factor industrial customers Dr. Boerger referenced. Therefore, Mr. Phillips stated it is misguided to attempt to reinterpret past orders based on a nonstandard theory that was not raised previously and rests on a faulty rationale.

Mr. Phillips testified that the Implementation Agreement locks in cost recovery from Rate 831 customers based on 194.556 MW of firm demand under five-year contracts, which allows NIPSCO to retain firm load in the face of the risk that industrial usage on the system would continue to decline. In response to the OUCC and CAC witnesses' contention that the risk of the loss of industrial load does not justify the approval of the Implementation Agreement, Mr. Phillips testified that the risk of additional loss of load is immediate and substantial. He pointed to BP's self-supply arrangement and US Steel's potential additional cogeneration project if Rate 831 is not approved. He added that ArcelorMittal has already reduced load served by NIPSCO by 50% since 2011 due to closing facilities and generating more power internally in response to NIPSCO's rates. He stated there is continuing pressure to cut NIPSCO's load by shifting production to other locations or increasing internal generation because costs are consistently higher in locations served by NIPSCO than in other ArcelorMittal facilities. He added that Praxair is evaluating significant

self-generation projects. Mr. Phillips testified that absent the revenue stability provided by Rate 831, NIPSCO faces continued loss of industrial load, which would lead to a cycle of rate cases that would result in further increases making NIPSCO's service less viable for industrial customers.

Mr. Phillips explained that the Implementation Agreement would provide full cost recovery of system costs for the firm load being served under Tier 1, including the cost associated with legacy production assets and depreciation expenses relating to planned retirements. He added NIPSCO will continue to collect transmission revenue from Rate 831 customers on their non-firm load under Tier 2 and 3 as well as under Tier 1. Mr. Phillips also noted that the contractual commitments under the Implementation Agreement will provide NIPSCO with a more reliable projection of capacity needs and facilitate a more orderly transition to a new resource portfolio.

Mr. Phillips stated that the alleged cost shift and Rate 831 subsidy are both inaccurately described and incorrectly computed. He noted that the OUCC and CAC witnesses treat Rate 831 as if it were a rate decrease instead of a revenue reduction aligned with the decreased use of NIPSCO's assets. He added that Mr. Wallach's computation improperly allocates production cost to interruptible load, which is contrary to cost of service principles. Mr. Phillips referred to his cross-answering testimony relating to the flaws in Mr. Wallach's computation and also explained that the studies provided in response to CAC data request 11-001(b) and (c) are flawed for the same reasons. Mr. Phillips explained that allocating generation investment to interruptible load and then subtracting revenue credits does not fix the erroneous allocation of production cost. He stated that subtracting revenue credits reduces the rate of return of those particular rate classes, which creates the opposite effect of fixing the erroneous allocation of costs. He added that the revenue credits do not equal the generation cost erroneously being allocated to interruptible load because the revenue credits are less than the generation cost being allocated. Mr. Phillips also stated that Mr. Wallach only used $42.6M in revenue credits, which was less than the credits actually paid. He added there are other issues with the Rates 732, 733, and 734 COSS Mr. Wallach relied upon because it includes different riders than the 800 series would have under NIPSCO's proposal. The revenue requirements and fuel costs used were larger than used for settlement, the removal of the BP load may be inconsistent with NIPSCO's treatment of the removal in the COSS in this case, and the study fails to normalize the 2017 loads for allocation.

Mr. Phillips also disagreed with Mr. Wallach's assertion that the aggregation of metering for BP and WCE would result in a cost shift and provide a subsidy to industrial customers. He noted that self-supply arrangements are expressly encouraged as a matter of public policy under Indiana and federal law and that BP's use of privately owned generation assets to supply power to itself results in a decrease in the electric service from NIPSCO. Consequently, NIPSCO will collect less revenue from BP because it will sell less power to BP. Mr. Phillips stated that is no more of a cost shift than any change in demand between rate cases and does not establish any subsidy that industrial customers will enjoy at the expense of other rate classes.

In response to the OUCC and CAC witnesses' arguments that the industrial customers should be required to provide a higher level of cost recovery for NIPSCO's legacy production assets, Mr. Phillips explained that the Commission has consistently recognized that interruptible service enables NIPSCO to avoid building generation capacity to serve that load to the benefit of all ratepayers. In addition, NIPSCO's largest industrial customers have invested in private generation assets, which reduces the incremental load that NIPSCO had to build and maintain

generation capacity to serve. He said that if NIPSCO had been required to build additional capacity to serve the interruptible load and the self-supplied load as firm demand, the magnitude of unrecovered cost for legacy production assets would be much greater than it is currently. Consequently, Mr. Phillips stated that the large industrial customers have mitigated the magnitude of the legacy costs through their interruptible service and self-supply arrangements and have also paid their allocated share for the bulk of NIPSCO's historical investments in coal-fired generating units, while providing massive rate subsidies to residential customers over that same period.

Mr. Phillips also noted that the large industrial load serviced by NIPSCO today is a very different set of customers from those on the system when the legacy production investments were made. He testified there is no expectation that the prior customers would be obligated to continue providing cost recovery 40-50 years into the future and that subsequent customers would take on that obligation.

In response to the OUCC's and CAC's criticism of the Implementation Agreement providing for a 4CP allocation, Mr. Phillips said that NIPSCO had proposed the 4CP method in its original filing, that the industrial parties had filed testimony supporting that allocation, that the 4CP method is consistent with how NIPSCO designs and operates its system and represents sound ratemaking. He also explained that the Implementation Agreement, by locking in firm Tier 1 demand commitments, eliminates the need for a second phase.

In response to Dr. Boerger's suggestion that Tier 1 commitments could be filed as a standalone without predetermining other issues, Mr. Phillips explained that Rate 831 customers cannot commit to a level of firm demand without knowing what the rates would be. Mr. Phillips testified that the Implementation Agreement provides significant value that had not previously been established. He noted that the possibility material changes to Rate 831 could lead to withdrawal of the proposal has been present throughout the case and not introduced for the first time by the Implementation Agreement.

Mr. Phillips also addressed Dr. Boerger's arguments regarding NIPSCO's tracker allocations. Mr. Phillips testified NIPSCO has not changed the proposed allocation from its case-in-chief; all the Implementation Agreement does is update the agreed reduction in revenue requirements. He noted that Dr. Boerger did not raise any objection to the proposed allocation in his direct testimony. Mr. Phillips added that allocating the demand allocators on firm demand is appropriate for the same reasons allocating base rate costs only on firm load is appropriate. The Rate 831 customers' Tier 2 and 3 loads will not be served using NIPSCO's production resources and therefore should not have trackers allocated on that load.

As to Dr. Boerger's objection to the revision of the adjacent customer facilities, Mr. Phillips explained that the proposed change was to resolve a longstanding dispute between NIPSCO and one of its large customers. He said the change maintains the status quo for the facilities at issue in Cause No. 45078 by determining the amount of energy subject to the transmission charge on a monthly basis.

C. US Steel Witness Georgis. Mr. Georgis addressed the OUCC's and CAC's Rate 831 Settlement opposition. Mr. Georgis testified that the Rate 831 Settlement preserves the fundamental rate and structure of Rate 831 and fully recovers the settled revenue requirement

associated with the large industrial class. Mr. Georgis observed that under the Rate 831 Settlement, large industrial customers proactively agreed to commit to a set amount of Tier 1 Firm Contract Demand elections and a demand rate that fully recovers the required settled revenue requirement for the 831 rate class. He noted that without such a commitment, the Revenue Settlement as it relates to Rate 831 is meaningless because no customer can be forced, either by NIPSCO or the Commission, to take a set level of firm demand. He testified that the Rate 831 firm Tier 1 service offering is similar to the status quo, in that NIPSCO and its large industrial customers currently have contracts under the existing Commission-approved interruptible rate structure that commits those customers to a certain level of firm service.

Mr. Georgis disagreed with Dr. Boerger's distinction between mitigation and subsidy, noting that the terms go hand in hand. He observed that if there is no subsidy in the rate structure, there is no need for mitigation, but as the Rate 831 Settlement notes, there is a sizable subsidy in NIPSCO's residential rates. Mr. Georgis concluded that if Rate 811 is not paying its cost of service, it is being subsidized. He stated that in addition to the subsidy in the settled revenue requirement, Rate 831 is further subsidizing other customer classes based on the transmission portion of the ACOSS. He noted that five of the large industrial customers are paying $17 million more than their cost of service for transmission and subsidizing the transmission costs of other customer classes. He noted that a sixth customer will only increase this level of transmission subsidy, which was ignored by the OUCC. Mr. Georgis testified that the Commission should not look at Rate 831 in isolation and ignore years of subsidization by large industrial customers to the benefit of other customer classes. He stated that without the approval of Rate 831, upward movement in NIPSCO's rates and sustained subsidization will cause the continued bypass of NIPSCO's system by large industrial customers.

Mr. Georgis refuted Dr. Boerger's claim that industrial customers are more risky and presumably should be allocated additional costs. He noted that for years, Rate 831 customers have paid a subsidy and premium. He testified that NIPSCO's rates are already too high and are not competitive, which is why US Steel's existing cogeneration is beneficial and future cogeneration is still a possibility if Rate 831 is not approved. He also stated that increased rates for large industrial customers will exacerbate the departure of industrial load, which increases rate volatility and risk for other customer classes. Mr. Georgis testified that the OUCC's proposal amplifies the existing uncompetitive rate environment rather than creating the competitive, cost-based solution that Rate 831 provides while helping to ensure that large industrial customers commit to staying on NIPSCO's system and pay a cost-based share of system costs.

Mr. Georgis also refuted Dr. Boerger's claims that the loss of additional US Steel load if Rate 831 is not approved would be modest. He noted that it is important to look at the financial impact of the US Steel load within the context of the position that the OUCC is taking on Rate 831. Under Rate 831, he explained that large industrial customers have a combined firm revenue allocation of $149.438 million. While not indicative of any one particular customer's share, he testified that on average, there is a $24.9 million contribution to the revenue requirement for each of the six large industrial customers, which is more than the $20 million lower end of the OUCC's alleged Rate 831 "cost shift" range. Mr. Georgis testified that these demand costs would shift to other customers if US Steel installed additional cogeneration and took additional firm load off of NIPSCO's system. Mr. Georgis concluded that the financial impact of just one large industrial

customer leaving NIPSCO's system is well within the range of the $20 million to $40 million in "cost shifting" that the OUCC argues exists under Rate 831.

Mr. Georgis also refuted Dr. Boerger's claim that the Rate 831 AAQFPTC is unreasonable. He noted that Rate 831 already overpays on transmission relative to NIPSCO's cost of service, so increasing the AAQFPTC exacerbates that problem. He testified that while NIPSCO refined the inputs, the methodology for calculating the AAQFPTC remains the same as originally proposed and accurately reflects the impacts of both settlements.

In response to Dr. Boerger's recommendation that NIPSCO recalculate its demand allocation tracker allocators to eliminate the Rate 831 Tier 1 adjustment, Mr. Georgis testified that these tracker costs are only applicable to NIPSCO full requirements customers or portions of customers' loads that are full requirements service. He explained that Rate 831 Tier 1 service is full requirements service, while Tier 2 and 3 are not. Mr. Georgis stated that the Demand Allocation referenced by Dr. Boerger is used for the RTO and FMCA riders, but these riders are not applicable to Tiers 2 and 3 because Rate 831 customers are buying energy in the wholesale market. Mr. Georgis testified that large industrial customers should not pay NIPSCO's system costs covered by these riders because they are not using NIPSCO's system under the market-based rate concept. He stated that the only part of NIPSCO's system that US Steel will use is bulk transmission, and those transmission costs are appropriately recovered under the Rate 831 tariff.

Mr. Georgis noted several practical problems with Dr. Boerger's suggestion that if Rate 831 is not approved, the Commission can address large industrial rates in a Phase 2 proceeding setting rates based on the existing 700 series rate design. First, he testified that eliminating the proposed and settled rate design of the largest load on NIPSCO's system that ensures full cost recovery and replacing it at a later date while all other elements of NIPSCO's rate structure remain static leads to significant uncertainty and potential volatility. Second, such a result would not allow Rate 831 customers proper time to plan and evaluate customer and bill impacts and implications of the rates. Finally, he stated the current and proposed rate structures are not an "apples to apples" comparison, and the rates should not be delayed and potentially replaced in this way.

Mr. Georgis testified that under the Rate 831 Settlement, US Steel has agreed to accept a rate design that it still believes, at least in part, contains subsidies. He noted that to request those subsidies continue in another form or alternative rates that provide none of the benefits of Rate 831 is neither fair nor equitable. Mr. Georgis observed that none of the large industrial customers qualify under any other of NIPSCO's proposed rate classes, and NIPSCO has not presented any form or pricing of an interruptible credit in this proceeding, which is a key element of the existing 700 series rates. Mr. Georgis concluded that in the event Rate 831 is not approved, customers should be permitted to revisit arguments regarding the full access, functionalization, and allocation of costs so that they have a fair opportunity to present evidence to the Commission regarding proper rate design for all customers.

Mr. Georgis testified that CAC's witnesses mischaracterize Rate 831 as a subsidy to industrial customers. Mr. Georgis emphasized while large industrial customers' rate revenues are decreasing from current levels, this is largely because their rates reflect the true cost of service since they are no longer procuring the vast majority of their power from NIPSCO. Mr. Georgis testified that under Rate 831 large industrial customers still must pay to cover their load, either via

the market pass-through rates under Tier 2, or to a third party under Tier 3. He also noted that while Rate 831 customers have the opportunity to benefit from the market, they are also taking on risk. He concluded that Rate 831 is simply not a "guaranteed win" for large industrial customers, nor is it a guaranteed rate savings. Instead, Mr. Georgis testified that Rate 831 is a regulatory solution to the problem of NIPSCO's continued load loss and provides an economic alternative for some of the largest companies in Indiana to remain customers of NIPSCO.

28. Commission Discussion and Findings.

A. Settlement. Settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coal. of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.*, 664 N.E.2d at 406.

Furthermore, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Pub. Serv. Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Revenue Settlement or Rate 831 Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Revenue Settlement and Rate 831 Settlement are reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such agreements serve the public interest.

Our review of the reasonableness of the Revenue Settlement and Rate 831 Settlement is aided by the comprehensive scope of the Revenue Settling Parties' and Rate 831 Settling Parties' agreements as well as the extensive evidence of record that addresses competing positions on a wide range of issues, including: (1) the cost of common equity; (2) calculation of NIPSCO's capital structure; and (3) the financial basis for results at present, proposed, and settlement rates. Each of these issues was addressed in testimony that considered a range of proposed outcomes. The evidentiary record provides a thorough consideration of the merits of the issues presented, thereby affording the Commission with a detailed record from which to make findings and conclusions.

We first address the Rate 831 Settlement and then the Revenue Settlement, which is impacted by our decision on the Rate 831 Settlement.

B. Rate 831 Settlement. In reviewing NIPSCO's proposed Rate 831 industrial service structure and the Rate 831 Settlement, we first recognize that NIPSCO's system is uniquely situated from other Indiana electric utilities. Industrial customers comprise less than 1% of total NIPSCO customers but account for more than 56% of its energy sales, and NIPSCO's five largest customers reflect 40% of NIPSCO's load. This large concentration of load in a few specific customers presents a distinct business risk for NIPSCO. This risk is heightened by the fact that these customers are mostly large, sophisticated energy users competing in global and domestic

markets characterized by sustained low natural gas prices and historically low cost of capital. These factors further incent industrial customers to utilize new or existing self-generation facilities to wholly or partially serve their energy needs.

Over the years, the Commission has found it to be in the public interest for NIPSCO to utilize the interruptible service characteristics of its large industrial customers. In Cause No. 43969, NIPSCO expanded its long-standing use of interruptible service to be integrated into the evolving MISO market. In Cause No. 43969, seven customer premises took service subject to Rider 675, and NIPSCO's capacity requirements in the MISO market were reduced by approximately 377 MW. In Cause No. 44688, we approved NIPSCO's proposed expansion of the availability of the interruptible rate at the request of its industrial customers. This expansion of interruptible load in turn allowed NIPSCO to reduce its capacity requirements by approximately 530 MW to the benefit of all customer classes. Given this context, NIPSCO developed its proposed Rate 831 industrial service structure as an evolution of its current interruptible service option approved by the Commission in NIPSCO's last two rate case orders.

In its Petition, NIPSCO requested that the Commission approve its proposal for a new industrial service structure as an ARP. NIPSCO elected, pursuant to Ind. Code § 8-1-2.5-4, to become subject to the provisions of Ind. Code § 8-1-2.5-6 for this purpose, and requests that the proposed industrial service structure be found to be in the public interest pursuant to Ind. Code § 8-1-2.5-6. The Rate 831 Settlement modifies, and provides the means to implement, the proposed ARP. As such, we assess the Rate 831 Settlement as an ARP under the provisions of the ARP Statute.

The legislative policy set forth in Section 1 of the ARP Statute anticipates the implementation of flexible alternatives to traditional regulatory practices and structures, and recognizes that amidst a changing energy environment, such flexibility is "essential to the well-being of the state, its economy, and its citizens." Moreover, pursuant to Ind. Code § 8-1-2.5-1(6), we are specifically authorized to implement such flexible alternatives.

NIPSCO seeks approval of the Rate 831 industrial service structure under Ind. Code § 8-1-2.5-6, which provides:

> (a) Notwithstanding any other law or rule adopted by the commission, except those cited, or rules adopted that pertain to those cited, in section 11 of this chapter, in approving retail energy services or establishing just and reasonable rates and charges, or both for an energy utility electing to become subject to this section, the commission may do the following:
>
> > (1) Adopt alternative regulatory practices, procedures, and mechanisms, and establish rates and charges that:
> > > (A) are in the public interest as determined by consideration of the factors described in section 5 of this chapter; and
> > > (B) enhance or maintain the value of the energy utility's retail energy services or property;

including practices, procedures, and mechanisms focusing on the price, quality, reliability, and efficiency of the service provided by the energy utility.

(2) Establish rates and charges based on market or average prices, price caps, index based prices, and prices that:

(A) use performance based rewards or penalties, either related to or unrelated to the energy utility's return or property; and

(B) are designed to promote efficiency in the rendering of retail energy services.

We may approve, reject, or modify the plan; however we may not make material modifications without NIPSCO's consent. Ind. Code § 8-1-2.5-6(d). In evaluating an ARP submitted under Ind. Code § 8-1-2.5-6, we are directed by Ind. Code § 8-1-2.5-6(a)(1)(A) to make a public interest finding "as determined by consideration of the factors described in section 5 of this chapter." Therefore, in determining whether the public interest will be served by this limited declination of jurisdiction, Ind. Code § 8-1-2.5-5(b) requires that we consider the following:

1. Whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;

2. Whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;

3. Whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency; and

4. Whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

It is against these statutory criteria, and in light of the legislative policy set out in Ind. Code § 8-1-2.5-1, that we evaluate NIPSCO's request to approve its ARP seeking to establish the proposed industrial service structure as implemented through the Rate 831 Settlement.

As we consider the first factor, there is ample evidence in the record that changes in the technology, operational conditions, and competitive forces support approval of the Rate 831 Settlement. It is uncontroverted that NIPSCO's large industrial customers utilize energy intensive processes and are sophisticated market participants competing on the basis of price globally. Given this competitive marketplace and the ability of NIPSCO's large industrial customers to reduce their demand on NIPSCO's system through self-generation or relocation, we agree with NIPSCO and find that now is the time to address the risks presented by its large industrial customers as NIPSCO simultaneously addresses its on-going generation needs. Service under Tiers 2 and 3 of Rate 831 will be set by competitive forces administered by MISO under FERC jurisdiction. Furthermore, NIPSCO's proposal requires its largest industrial customers to remain as its retail customers, while at the same time providing more market choices. The Commission has considered the evidence presented and finds that the Rate 831 Settlement meets this first factor.

Regarding the second factor, the evidence supports the conclusion that approval of the Rate 831 Settlement will benefit the energy utility, its customers, and the state. The evidence shows that NIPSCO has already lost a significant amount of its industrial load due to customer self-generation and customers shifting or closing production. Furthermore, the evidence demonstrates that NIPSCO is at risk of losing more industrial load in the absence of a change in service structure to better align industrial rates with cost of service.

Assessing the severity of the risks of large industrial bypass requires informed judgment. The record shows that NIPSCO has closely examined the global trends affecting its steel-making and other largest loads as well as facility-specific actions that are under consideration. Based on this analysis, NIPSCO has proposed Rate 831 to ameliorate the substantial threat posed by potential industrial load loss. The record shows that approval of Rate 831 would reduce NIPSCO's long-term business risk because the amount of firm load it is obligated to serve for at least five years would be more certain. We find the record describing BP's actions to self-serve its load, the testimony detailing the planned or potential actions by US Steel and Praxair, and the significant reduction of ArcelorMittal load to be persuasive evidence warranting a proactive response by NIPSCO.

The Commission understands that the OUCC and CAC opposed approval of the Rate 831 Settlement and considered their arguments that the Rate 831 Settlement: (1) avoids NIPSCO's legacy cost burden by passing it on to other rate classes; (2) implements a cost allocation methodology unfair to other rate classes; (3) eliminates the opportunity to ensure the transmission charge for backing up self-generation reflects the cost of service; and (4) modifies NIPSCO's proposed adjacent facilities transmission charge such that it no longer reflects cost of service. The OUCC also recommended the Commission require NIPSCO to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1 Adjustment in Exhibit A to the Rate 831 Settlement. The CAC argued that the Rate 831 Settlement is not in the public interest because it would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes and by allocating those costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand.

By analyzing the prudence of Rate 831 through a fixation on the near-term impacts to other rate classes, the OUCC, CAC, and other parties fail to recognize the substantial long-term risks addressed by this decision. What these parties qualify as a subsidy for Rate 831 customers is a mischaracterization that ignores the fact that Rate 831 is a fully costed rate designed at parity. NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers while addressing its aging generation and navigating a dynamic economic environment. Although the Rate 831 proposal requires NIPSCO's other customer classes to pay higher rates in the near term than they are currently paying today under the existing service structure, the long-term risk is that these large industrial customers will otherwise exercise their options to significantly shift load off NIPSCO's system. When that occurs, costs might reasonably be reallocated to the remaining customer classes. While the OUCC and CAC focused on the fairness of a cost shift within this rate case between Rate 831 and other classes, the record shows that denying Rate 831 now would likely result in even higher costs, which would otherwise have been collected under Rate 831 if these customers further bypass NIPSCO's service. When considering the full range of impacts in play

rather than just the near-term cost shift, Rate 831 is a reasonable solution now rather than later. We find that retaining the current service structure would only increase the risk that these customers will exercise their options to self-generate additional power or relocate production to avoid an increasing NIPSCO electric price.

Given that large industrial customers constitute such a significant portion of NIPSCO's retail electric sales, reducing their load would cause precipitous declines in NIPSCO's revenues and operating margins far faster than could be offset by growth in other sectors. In the long run, we find that such load loss would subject remaining customers and customer classes to increased costs above and beyond the near term costs of the Rate 831 Settlement. Conversely, we find that approval of this new service structure will provide Rate 831 customers increased flexibility to meet their electricity requirements and improve their ability to compete in global markets while other customers and the utility benefit from reduced risks and greater certainty in large industrial load for a set period of time.

For the foregoing reasons, we find the Rate 831 Settlement is a reasonable proposition to retain industrial load, and its approval is beneficial to NIPSCO and all of its customers. As such, the Rate 831 Settlement satisfies the second factor.

The Commission finds that the Rate 831 Settlement also meets the third factor by promoting utility efficiency. In particular, Rate 831 reduces the amount of replacement capacity NIPSCO must plan for, provides more reliable load projections for planning purposes, and mitigates the risk of building excess capacity.

As NIPSCO begins to implement the results of its IRP and procure replacement capacity, NIPSCO needs to ensure some stability in what its obligation to serve will be for its largest industrial loads. Rejecting Rate 831 and retaining the current industrial service structure would only increase the risk that NIPSCO's industrial load will further decline over time thereby creating unrecovered costs. NIPSCO would simultaneously be forced to modify its existing Rate 732, 733, and 734 service structure to re-integrate the Rate 831 customers. In that alternative, NIPSCO would likely seek to modify the existing Rate 732, 733, and 734 industrial service structure, alter Rider 775 registrations, and restructure NIPSCO's back-up and maintenance service. These hypothetical proposals to attain some near-term load stability would not actually reduce the risk that industrial customers will exercise their options in the future. We find that approval of the Rate 831 Settlement would demonstrably improve NIPSCO's ability to forecast the load it is required to serve and would thereby enhance its accuracy in procuring the appropriate amount of replacement capacity for its aging generation resources. Likewise, approval of the Rate 831 Settlement will also enable NIPSCO to make better resource decisions while maintaining system reliability and resiliency. As such, we find that the Rate 831 Settlement satisfies the third factor by promoting utility efficiency through more accurate load forecasts and corresponding capacity procurement.

Finally, regarding the fourth factor, a review of the evidence shows that, without the approval of the Rate 831 Settlement, NIPSCO will be hindered in its ability to compete with alternative sources of energy supply and risks further migration of load from its largest industrial customers.

Based on the evidence, we find that NIPSCO is facing the prospect of retiring aging generation resources and procuring replacement capacity in the near term. Despite current strong economic conditions, NIPSCO Electric operations continue to face declining industrial usage driven by the development of customer-sited generation and uncertainty in some global industrial markets. We find that the electric industry is in the midst of a transformation, and it is crucial that NIPSCO be in a position to flexibly align with this transformation.

In past orders, NIPSCO has been permitted to allow its large industrial customers to assume more market risk through the use of interruptible service offerings. The new industrial service structure is the next step in this evolutionary process. In exchange for taking a set amount of contract demand for a period of five years, NIPSCO's largest, most sophisticated customers will be allowed to make more decisions regarding their energy procurement. Transitioning much of NIPSCO's industrial load to Rate 831 requires better cost recovery alignment resulting in a near-term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward. We find that if NIPSCO does not respond, there is a high probability that more industrial load will leave the system, and once gone, the chances that it will return are low.

Based on this evidence and the findings made above, the Commission finds that the Rate 831 Settlement meets the fourth factor and that NIPSCO's proposed ARP, as embodied in the Rate 831 Settlement, is in the public interest.

The Commission has considered the Section 5(b) factors and the evidence, and we find that they support approval of NIPSCO's proposed ARP. We find the proposed ARP and Rate 831 Settlement are consistent with the legislative policy set forth in Ind. Code § 8-1-2.5-1. We are mindful of NIPSCO's unique reliance on a small number of very large industrial loads that are subject to intense global competitive pressures. We find that technological conditions and competitive forces are rendering traditional regulation over NIPSCO's industrial service structure less efficient and potentially more costly because, if a change is not made, more industrial load is reasonably expected to leave the system of customers supporting NIPSCO's retail service cost thereby creating future cost-recovery risks. It is not in the public interest to ignore the challenges of NIPSCO's traditional rate structure in the face of demonstrated and probable industrial load loss, and we are not inclined to adopt a purely reactive approach. By declining to exercise our traditional jurisdiction and embracing the alternative structure that is captured in the Rate 831 Settlement, we find that NIPSCO, all of its customers, and the State should benefit by preserving a defined level of firm large industrial load and avoiding the effects of stranded cost that might reasonably otherwise occur. In so doing, we promote energy utility efficiency by allowing NIPSCO to better plan for the firm load it must serve and by allowing NIPSCO to "right size" its generation resources and avoid the future potential inefficiencies of maintaining excess capacity.

The record demonstrates that if the Rate 831 Settlement, the Revenue Requirement as embodied in the Revenue Settlement, and NIPSCO's proposed cost allocation are approved, there will be no need for a Phase 2 proceeding to establish revised rates. Exhibit D to the Rate 831 Settlement specifically addresses implementation concerns previously raised by some industrial customers.

The Rate 831 Settlement also resolves contested issues regarding the design of Rate 831 that would otherwise require litigation or a true-up process. In particular, each Rate 831 customer has agreed to subscribe to a specific level of firm, Tier 1 demand. Additionally, the parties agreed that the design of Rate 831 should be based on NIPSCO's COSS with costs allocated to Rate 831 based on 194.556 MW of firm demand. These agreements confirm the subscription levels of the Rate 831 customers and establish a cost allocation based on that firm demand, which not only eliminates the need for a true-up process but provides certainty to the Commission and the other parties regarding the share of costs being allocated to Rate 831. The actual Tier 1 subscription is also below that used by NIPSCO in setting cost allocation, but through the Rate 831 Settlement, Rate 831 customers will cover the costs of the 194.556 MW used to allocate costs.

The OUCC and Walmart proposed assessing transition charges on Rate 831 customers. We note that the Commission has no direct statutory authority to prohibit any customer from building or utilizing self-generation nor do we have the ability to preclude a large industrial customer from reducing consumption or moving its operations to another location. In these instances, no transition costs are paid. Rather, as in this case, NIPSCO could file another rate case, seeking to recover the lost revenue from its remaining customers. Moreover, the implementation of transition charges would defeat the purpose of the Rate 831 service structure, which is to maintain load by creating a cost-based rate and providing access to market-priced capacity and energy, not to make NIPSCO's industrial rates less competitive. Based upon the evidence presented, we find that the proposed Rate 831 service structure is reasonable and that no transition charges should be assigned to Rate 831 customers.[43]

In conclusion, the record demonstrates that it was appropriate and reasonably necessary for NIPSCO to revise its industrial rate structure in order to mitigate the credible and preventable threat of large industrial load loss. The record also demonstrates that it is important to NIPSCO and all of its customers to retain the Rate 831 customers and for them to continue contributing to NIPSCO's fixed production costs. We now find that NIPSCO's proposed Rate 831 service structure and the Rate 831 Settlement will best position these large industrial customers to remain cost competitive within their global markets while continuing to contribute to NIPSCO's fixed production costs to serve. This balance enables these customers to be more economically competitive and provides certainty to NIPSCO regarding its obligation to serve. We find that NIPSCO's proposed ARP to implement Rate 831 is in the public interest and will enhance or maintain the value of NIPSCO's retail energy services or property. For the foregoing reasons, the Rate 831 Settlement and Implementation Agreement are approved.

C. Revenue Allocation. We next address the allocation of costs to the various customer classes, as proposed by NIPSCO, and embedded in the terms of the Rate 831 Settlement.

Having considered the evidence presented on the issue of cost allocation, we find the 4CP allocation as proposed by NIPSCO and as reflected in the Corrected Rate 831 Implementation Agreement Exhibit A to the Rate 831 Settlement is reasonable and in the public interest, and is,

[43] While no transition charge is assigned to Rate 831 customers, a risk reduction transition adjustment resulting in a revenue requirement decrease of $3,876,748 is allocated to all non-Rate 831 and Rate 844 customers, as discussed in section 28.D.4.

therefore, approved. The 4CP method for NIPSCO is appropriate for cost allocation based on the fact that in recent years the system peaks in the months of June – September were almost always within 90% of the annual peak, but none of the other eight months were ever within 90% of the annual peak. The FERC tests utilized by Dr. Gaske are a commonly used method for analyzing system load characteristics and determining whether a utility has monthly peak periods that can be distinguished from off-peak periods. The 4CP allocation is consistent with the design and operation of NIPSCO's system, and it appropriately and reasonably aligns cost allocation with cost causation.

NIPSCO proposed a mitigation plan to keep Rate 831 at parity and provided for an across-the-board percentage rate increase. NIPSCO began with a fully ACOSS and then developed rates for NIPSCO's Rate 831 customers at parity utilizing the proposed industrial service structure and allocating 184.556 MW of demand at the meter to the industrial class. NIPSCO then allocated the additional revenue requirement over all customer classes equally. NIPSCO proposed the methodology to avoid rate shock to its Residential customers, and this approach aims to mitigate the rate increases so that no class will see an unusually large increase in its base rates while allowing NIPSCO to retain its large industrial customers on the system. Because of residential class subsidies that were retained in prior rate proceedings and the combination of industrial service restructuring and other cost increases, the residential customers would require a rate increase in excess of 30%. Therefore, to mitigate this impact, it was determined that all classes except Rate 831 should receive the same across-the-board percentage rate increase, and the rates for the large industrial class would then be based on the allocated cost of service.

CAC recommended that Rate 831 revenues be maintained at test-year levels under current rates and that the revenues of all other customer classes be increased by an equal percentage. Other than its proposal for a transition charge, the OUCC agreed that it is reasonable to assign the remaining increase across the customer classes on an equal percentage basis. NLMK argued that NIPSCO's proposal reasonably addresses its concerns about industrial bypass and rate mitigation. The Industrial Group agreed with NIPSCO's proposal. Walmart recommended that, if it is not possible to eliminate inter-class subsidies in this case, the Commission should establish a path to eliminate or reduce subsidies in future cases.

With the exception of Walmart, no party opposed NIPSCO's mitigation proposal after the Revenue Settlement was entered. Based upon the evidence of record, we find NIPSCO's request to keep Rate 831 at parity and to provide for an across-the-board percentage rate increase, except for Rate 844 and Rate 850 as discussed below, is supported by substantial evidence, in the public interest, and approved.

Based upon this conclusion, we find that the relevant allocations should be as follows:

Demand Allocation		
Class	Rate Schedule	Allocation
Residential	Rate 811	35.05%
C&GS Heat Pump	Rate 820	0.06%
GS Small	Rate 821	17.50%
Comml SH	Rate 822	0.08%
GS Medium	Rate 823	11.42%

GS Large	Rate 824	14.33%
Metal Melting	Rate 825	0.50%
Off-Peak Serv.	Rate 826	8.34%
Ind. Pwr Serv. – Large – Tier 1	Rate 831	8.32%
Small Industrial Service – LLF	Rate 832	0.88%
Small Industrial Service – HLF	Rate 833	1.99%
Muni. Power	Rate 841	0.24%
Int WW Pumping	Rate 842	0.01%
Railroad	Rate 844	0.15%
Street Lighting	Rate 850	0.54%
Traffic Lighting	Rate 855	0.06%
Dusk-to-Dawn	Rate 860	0.18%
Interdepartmental	Interdepartmental	0.34%
Energy Allocation		
Class	Rate Schedule	Allocation
Residential	Rate 811	28.86%
C&GS Heat Pump	Rate 820	0.09%
GS Small	Rate 821	13.67%
Comml SH	Rate 822	0.10%
GS Medium	Rate 823	10.69%
GS Large	Rate 824	15.54%
Metal Melting	Rate 825	0.78%
Off-Peak Serv.	Rate 826	10.72%
Ind. Pwr Serv. – Large – Tier 1	Rate 831	13.86%
Ind. Pwr Serv. – Large – Tier 2		0.00%
Small Industrial Service – LLF	Rate 832	1.23%
Small Industrial Service – HLF	Rate 833	3.30%
Muni. Power	Rate 841	0.24%
Int WW Pumping	Rate 842	0.00%
Railroad	Rate 844	0.18%
Street Lighting	Rate 850	0.35%
Traffic Lighting	Rate 855	0.05%
Dusk-to-Dawn	Rate 860	0.12%
Interdepartmental	Interdepartmental	0.21%

TDSIC Allocation (based upon firm load)			
Class	Rate Schedule	Transmission Rev. Req. Allocation	Distribution Rev. Req. Allocation
Residential	Rate 811	36.64%	53.48%
C&GS Heat Pump	Rate 820	0.11%	0.19%
GS Small	Rate 821	15.94%	17.65%
Comml SH	Rate 822	0.12%	0.18%
GS Medium	Rate 823	11.67%	9.90%

GS Large	Rate 824	13.82%	10.77%
Metal Melting	Rate 825	0.48%	0.53%
Off-Peak Serv.	Rate 826	8.49%	5.98%
Ind. Pwr Serv. – Large	Rate 831	8.57%	0.00%
Small Industrial Service – LLF	Rate 832	1.05%	0.00%
Small Industrial Service – HLF	Rate 833	2.25%	0.00%
Muni. Power	Rate 841	0.25%	0.33%
Int WW Pumping	Rate 842	0.00%	0.00%
Railroad	Rate 844	0.14%	0.00%
Street Lighting	Rate 850	0.07%	0.27%
Traffic Lighting	Rate 855	0.04%	0.03%
Dusk-to-Dawn	Rate 860	0.04%	0.20%
Interdepartmental	Interdepartmental	0.31%	0.50%

There also was a dispute among the parties regarding the appropriate allocation of demand costs for trackers other than TDSIC. OUCC witness Boerger recommended that "NIPSCO be required to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1 Adjustment shown on Page .1 of Rate 831 Implementation Agreement Exhibit and in Attachment 19-E of Mr. Westerhausen's prefiled direct testimony in this case . . . ." Industrial Group witness Phillips and US Steel witness Georgis disagreed with that proposed revision and explained why the tracker allocations proposed by NIPSCO are consistent with system utilization and cost causation. Mr. Phillips stated that it is appropriate to allocate production trackers only to Tier 1 firm load because the Rate 831 customers do not use NIPSCO's production resources for their Tier 2 and 3 loads. At the hearing, Dr. Boerger repeatedly acknowledged during cross-examination that production costs should not be allocated to non-firm load. Tr. at D-94 – D-95, D-96 – D-97. Based upon the evidence of record, the Commission finds that the adjustments proposed in Mr. Westerhausen's prefiled direct testimony contained in Attachment 19-E should be approved.

D. Revenue Settlement. We now review and address the Revenue Settlement, which was opposed by the ICC, ICARE, and LaPorte. We note that the ICC and ICARE do not represent customers in this proceeding, and they explicitly did not oppose the Revenue Settling Parties' agreement to set depreciation accrual rates for the Schahfer and Michigan City coal units based on assumed lives ending in 2032. LaPorte's opposition to the Revenue Settlement highlighted NIPSCO's J.D. Power results and recommended that based on those results, the Revenue Settlement's ROE should be rejected.

(1) Rate Base Update Mechanism Process. For Step 1 Rates, NIPSCO proposed to update its requested relief to be effective subsequent to the receipt of the Commission's final order based upon an actual rate base and capital structure cutoff date of June 30, 2019. As part of its compliance filing, in addition to any other changes identified in this Order, NIPSCO will update its basic rates and charges to reflect the actual rate base and related depreciation and amortization expense, as well as the actual capital structure based on the June 30, 2019 cutoff date. NIPSCO proposed that these rates will become effective with the first billing cycle following the issuance of the Order and remain in effect until replaced by Commission-approved rates resulting from NIPSCO's proposed second compliance filing as part of Step 2.

For Step 2 Rates, the Revenue Settling Parties agreed Step 2 Rates will be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agreed not to include in rate base for Step 2 Rates plant in excess of the amount or value of plant projected in this Cause. The Settling Parties agreed that Step 2 Rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Step 2 Rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019, and calculate the Step 2 Rates using those certified figures. For purposes of this section, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2019. The Revenue Settling Parties and other parties to this proceeding will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Revenue Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 Rates took effect.

We find that the proposed rate base update mechanism process is reasonable, supported by evidence of record, and should be approved.

(2) Revenue Requirement and NOI. The Revenue Settling Parties agree that NIPSCO's base rates will be designed to produce a Revenue Requirement of $1,482,166,740 prior to the application of surviving Riders, which represents a decrease of $63,648,449 from the amount originally requested by NIPSCO. The Revenue Settling Parties also agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as agreed to in the Revenue Settlement, and a $2,000,000 decrease to NIPSCO's proposed O&M Expense. The Revenue Settling Parties agree that NIPSCO's Revenue Requirement results in a proposed authorized NOI of $271,211,585.

As discussed below, we find that the Revenue Settlement provisions regarding NIPSCO's revenue requirement, exclusive of the parties' agreed-upon ROE as discussed below, are reasonable, supported by evidence of record, and are approved. Based on our finding below regarding NIPSCO's authorized ROE, we find and authorize a Revenue Requirement of $1,453,163,108 for Step 1 rates and $1,478,289,992 for Step 2 rates.

(3) NIPSCO's Fair Value Rate Base. The Revenue Settling Parties agreed that the WACC times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based on the Revenue Settlement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding; (2) NIPSCO's proposed capital structure; and (3) an authorized ROE of 9.90%. Neither the components nor value of that fair value rate base is disputed by any party. However, given our finding below regarding NIPSCO's authorized ROE, NIPSCO's overall return for earning test purposes shall be 6.52%. Accordingly, we find that

NIPSCO's fair value rate base for purposes of this proceeding is $4,115,502,071, and that this fair value rate base should be used for purposes of Ind. Code § 8-1-2-6.

(4) NIPSCO's ROE. In its case-in-chief, NIPSCO requested an ROE of 10.80%. OUCC witness Woolridge suggested that NIPSCO's ROE could be set at 8.75%, but in recognition of the practice of gradualism, a 9.25% ROE would be more appropriate. NIPSCO Industrial Group witness Gorman recommended an ROE of 9.35%. Walmart witness Chriss suggested an ROE of 9.69%. The Revenue Settling Parties agreed to an authorized ROE of 9.90%.

In considering the Revenue Settling Parties' recommended ROE, we note that the Revenue Settlement was finalized, signed, and filed prior to the Rate 831 Settlement and Implementation Agreement. As such, the fate of NIPSCO's proposed Rate 831 large industrial service structure was still uncertain at that time. Furthermore, at no place in the Revenue Settlement is its approval made explicitly contingent upon approval of Rate 831. The Commission's approval of the Rate 831 Settlement and Implementation Agreement and the new industrial service construct designed in it significantly mitigates the risk of the loss of industrial load to NIPSCO and the associated earnings volatility. Therefore, based on this reduced risk for NIPSCO's shareholders, we find that a decrease in NIPSCO's ROE is warranted.

In response to the Commission's July 16, 2019 docket entry question, LaPorte witness Cearley stated that based on his review of Mr. Rea's testimony and NIPSCO's similar testimony in its last rate case, Mr. Cearley believes that a 25 to 50 basis point downward ROE adjustment is appropriate and reasonable due to NIPSCO's proposals in this case to address its environmental risk elements and its concentration of large industrial load. Mr. Cearley explained that this recommendation is further supported by his recognition in his direct testimony of the compounding effect of NIPSCO's repetitive "...risk adjustments to its return calculations based on environmental risks and its case-after-case request for upward risk adjustments due to a disproportionate level of large industrial load" in each of its last three to four rate case proceedings.

Based upon the totality of evidence presented and the reduced risk to NIPSCO as a result of our approval of the Rate 831 Settlement and Implementation Agreement, we find that the Revenue Settling Parties' agreed-upon ROE of 9.90% should not be approved. Instead, we find that an ROE of 9.75% is within the range of the ROE evidence presented and is approved, as it is reasonable and appropriate in light of the reduced business risk to NIPSCO as a result of approval of the Rate 831 Settlement. In addition, we note that the Rate 831 Settlement and Implementation Agreement explicitly assigns a revenue requirement to the Rate 831 customers. Further, the evidence in this case reflects the transition to the new industrial service has a distinct impact on the non-Rate 831 customers. Accordingly, this 15 basis point reduction and the resulting $3,876,748 revenue requirement decrease shall be applied across the board only to the customer classes experiencing a rate increase as the result of this Order. As such, Rate 831 and Rate 844 customer classes are exempt and are assigned their agreed-to revenue requirements identified in the Rate 831 Settlement. The application of this risk reduction transition adjustment is essentially funded by NIPSCO through a reduction in its ROE and provides a measure of relief to non-Rate 831 customers in light of the reduced risk to NIPSCO and is not inconsistent with the OUCC's transition charge proposal. Furthermore, the approved 9.75% ROE is consistent with Walmart Exhibit No. 2, Exhibit SWC-3 (REVISED) sponsored by Walmart witness Chriss showing that the

average ROE for vertically integrated electric utilities in the country from 2016 through July 10, 2019, is 9.73%.

(5) Depreciation and Amortization Expense. NIPSCO witness Spanos recommended depreciation accrual rates for NIPSCO's electric and common plant assets calculated in accordance with the depreciation study he sponsored. The only witnesses proposing changes to the depreciation accrual rates recommended by Mr. Spanos were OUCC witnesses Garrett and Blakley and Industrial Group witness Gorman, and their issues were resolved pursuant to the Revenue Settlement. No other evidence was presented that disputed the results of Mr. Spanos' depreciation study or the resulting accrual rates. Further, no evidence was presented disputing the Revenue Settlement depreciation accrual rates. We find that the Revenue Settling Parties' agreement regarding depreciation accrual rates should be approved. Those are the original depreciation accrual rates recommended by Mr. Spanos with the following exceptions: (1) the amortization period for retired coal-fired generating units as described in NIPSCO's case-in-chief shall conclude in 2032; and (2) annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency included in demolition costs. These are the depreciation accrual rates that should be used for purposes of determining NIPSCO's total revenue requirement and that should be used for purposes of depreciation expense that will accrue between the date of this Order and December 31, 2019, for purposes of NIPSCO's Step 2 rate base. Neither ICC nor ICARE took issue with the depreciation study or the depreciation rates that come out of the depreciation study. In fact, ICC witness Medine specifically acknowledged that she takes no issue with the depreciation rate for NIPSCO's steam production plant, which underlies the Revenue Settlement.

In the Revenue Settlement, NIPSCO agreed to implement a credit mechanism upon the retirement of its coal-fired generating units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. This credit mechanism was recommended by OUCC witness Blakley. Mr. Blakey testified that ratepayers should be credited with the effect of the annual depreciation of Schahfer and Michigan City plant. He explained that the credit mechanism would function similarly to a CWIP plant investment tracker, in which plant investment is reduced by associated depreciation over a period and the return "on" is calculated on the new lower net plant balance. While the plant investment is decreasing each year due to depreciation of the investment, NIPSCO would otherwise still receive a return "on" the investment as determined at the time of this rate case. The credit would reflect the difference between the amount authorized in rates and the actual investment amount adjusted for depreciation. The credit would be repeated annually until the physical asset or regulatory asset is fully depreciated or amortized. The credit will be limited to the net plant investment value of the Schahfer and Michigan City coal-fired generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in the Revenue Settlement Paragraph B.1(a); and (2) the NOI established in the Revenue Settlement Paragraph B.1(b) for purposes of its earnings test. NIPSCO agreed to hold annual meetings preceding the 30-day compliance filing with interested stakeholders. No party opposed the credit mechanism, and we find it is reasonable and should be approved.

ICC and ICARE were the only parties to oppose the provisions of the Revenue Settlement related to depreciation. Ms. Medine specifically stated that she takes no issue with the depreciation rate for NIPSCO's steam production plant underlying the Revenue Settlement. However, both witnesses Medine and Griffey testified that approval of NIPSCO's regulatory asset treatment

resulting from the Revenue Settlement is unnecessary at this time and should be deferred until the coal plants are actually retired. Mr. Griffey recommended that the Commission reject any aspect of the Revenue Settlement that forecloses flexibility and decline to approve explicitly or implicitly NIPSCO's retirement dates.

As noted by Ms. Shikany during cross-examination, approval of the Revenue Settlement – and the attendant depreciation/amortization of amounts based upon a 2032 date – results in zero difference in the revenue requirement agreed upon. Tr. at B-28. In fact, NIPSCO's agreement in the Revenue Settlement to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base at the time a final order is issued and the actual investment amount adjusted for depreciation as outlined in OUCC witness Blakely's direct testimony results in customer savings. Based upon all the evidence, the Commission finds that the depreciation rates agreed upon in the Revenue Settlement are reasonable and should be approved. However, in approving the agreed-upon depreciation rates, we do not, either explicitly or implicitly, approve NIPSCO's retirement dates.

During the hearing held in this Cause, NIPSCO witness Shikany explained the need for a determination regarding the treatment of the remaining book value of the Schahfer and Michigan City generating units at the time of their retirement. She explained that the Uniform System of Accounts is very prescriptive of how to treat a normal retirement. Tr. at B-33. She explained that under normal retirement accounting due to the use of composite depreciation, Mr. Spanos could assign sufficient accumulated depreciation to the Bailly assets to reflect a full recovery by reducing the accumulated depreciation. Tr. at B-33. However, she explained that once the Schahfer units are retired, there will not be enough time to collect the remaining book value through depreciation. Therefore, NIPSCO has proposed to treat the retirement as extraordinary, which needs the Commission's approval. Tr. at B-34. Based upon Ms. Shikany's explanation in Revenue Settlement rebuttal testimony and in redirect examination why a determination is needed at this point concerning the regulatory asset and the fact that customers are not adversely affected by such confirmation (as is further confirmed by the fact that no customer parties opposed this aspect of the Revenue Settlement) and that NIPSCO would face financial risk were we not to provide such confirmation, we therefore find that granting authority for the regulatory asset treatment contained in the Revenue Settlement is reasonable and in the public interest. Accordingly, we find that should the Schahfer and/or Michigan City generating units be retired before the end of 2032, the retirement(s) should be deemed extraordinary pursuant to the FERC Uniform System of Accounts. Further, we find that the net book value of the retiring unit(s) at retirement should be recorded as a regulatory asset when the units are actually retired; that the regulatory asset should be amortized over a period expiring at the end of 2032; that the annual amortization expense should be recovered through rates; and that the regulatory asset should be reflected in NIPSCO's net original cost rate base upon which a full return should be authorized for ratemaking purposes.

With respect to the remaining issue related to amortization expense, the evidentiary record includes proposals from NIPSCO and the OUCC proposing competing approaches to the amortization and amount of the regulatory assets for rate case expense, and for the amortization of the TDSIC deferred balance. The Revenue Settling Parties agreed to resolution of these issues providing that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding, with the exception that the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC Seven-Year Plan, FMCA,

MATS, EDR, and Electric Rate Case Expense of seven years, and that if it has not been already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO will make a tariff filing to reflect the reduction in amortization expense. We find this resolution to be reasonable and appropriate.

(6) Other Specific Ratemaking Issues. As discussed above, the Revenue Settling Parties agreed to a level of operating expenses to be incorporated in NIPSCO's revenue requirement, which includes the following issues:

a. TCJA. In its June 1, 1987 Interim Order issued in Cause No. 38194 adopting the recommendations of the Report of the Executive Committee on April 15, 1987, the Commission concluded that all excess deferred taxes should be passed back using the ARAM. After the adoption of the TCJA, the Commission opened an investigation in Cause No. 45032 into the impacts of that TCJA and possible rate implications. The first phase was to address immediate rate reductions to remove the difference between: (1) the amount of federal taxes that the given Rate or Charge was designed to recover based on the tax rate in effect at the time the Rate or Charge was approved; and (2) the amount of federal taxes that would have been embedded in the given Rate or Charge had the new tax rate applicable to NIPSCO as a result of the TCJA been in effect at the time of approval. The second phase was to address all remaining issues, including: (1) the amount and amortization of normalized and non-normalized excess ADIT and the regulatory accounting being used for estimated impacts resulting from the TCJA; and (2) the timing and method for how these benefits will be realized by customers, whether directly or indirectly.

In its sub-docket resulting from Cause No. 45032 (Cause No. 45032-S5), NIPSCO did not file a case-in-chief and instead filed an Unopposed Motion to Hold in Abeyance the Procedural Schedule, which was granted by the Commission on August 15, 2018. In its motion, NIPSCO proposed a method by which it would return excess income tax revenue recovered through rates between January 1, 2018 and April 30, 2018, which was at that time reflected as a regulatory liability and stated that the parties will resolve all other Phase 2 issues in a rate case to be filed by December 31, 2018.

In the Revenue Settlement, the Revenue Settling Parties agreed that: (1) NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in NIPSCO's revenue requirement at the ARAM, estimated at the time of the Revenue Settlement to be 26 years; and (2) with regard to NIPSCO's Unprotected and Other Excess ADIT balance, which totaled approximately $137,789,071 as of December 31, 2017, NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Step 2 Rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030, and if not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization. The total amount of unprotected excess ADIT to be passed back to customers will be addressed in NIPSCO's next general rate case.

The resolution proposed for issues associated with the return of excess ADIT balances is supported by the uncontested evidence of record. The utilization of ARAM as the basis for the pass back of ADIT associated with protected assets is consistent with regulations promulgated by the U.S. Department of Treasury. The amortization of unprotected and other excess ADIT is

subject to Commission discretion. We note that the amortization of excess ADIT as agreed to in the Revenue Settlement was uncontested by the non-settling parties. We find the proposed treatment of ADIT balances as proposed by the Revenue Settling Parties to be reasonable and in the public interest. This resolves all remaining issues in Cause No. 45032-S5.

b. Rate Design. In its case-in-chief, NIPSCO proposed an increase in the Residential Customer Charge from $14.00 to $17.00 per month. CAC proposed a reduction to $12.55. Sierra Club proposed a reduction to $12.77. The OUCC proposed no change to the Residential Customer charge. We find that the Revenue Settling Parties' agreement that rates should be designed with the Residential Customer Charge set at $13.50 per month is reasonable and should be approved.

In its case-in-chief, NIPSCO proposed to replace Rates 732 and 733 with Rate 830. The Industrial Group proposed low load factor and high load factor rates for Rate 830. We find that the Revenue Settling Parties' agreement that Rate 830 be split into Rates 832 and 833 to reflect the current structure of Rates 732 and 733 (as proposed in Industrial Group witness Phillips' direct testimony and NIPSCO witness Westerhausen's rebuttal testimony) and that those rates provide for back-up and maintenance provisions reflected in current Rider 776, is reasonable and should be approved.

The Revenue Settling Parties agreed that Rate 844 shall see no increase resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. We find this provision is reasonable and should be approved.

c. Tariff Changes – Trackers and Riders. The Revenue Settling Parties agreed: (1) NIPSCO shall flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; (2) NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years; and (3) NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief. We find this provision is reasonable and should be approved.

d. Low-Income Program Commitment. The Revenue Settlement includes a provision that NIPSCO commits to seek approval of a voluntary low-income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process that NIPSCO has already established with interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, will not impact NIPSCO's revenue requirement and will be discussed in the collaborative process. We find this provision is reasonable and should be approved.

e. Rate 850 – Street Lighting. The Revenue Settlement includes a provision that the lamp charge for TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. Pursuant to Joint Exhibit 8, the resulting revenue deficiency will be allocated to other customer and NIPSCO-owned lamp types

in Rate 850. We note no evidence was presented in opposition to this provision. We find this provision as modified by Joint Exhibit 8 to be reasonable and should be approved.

(7) Operating Income under Present Rates. For the 12 months ending December 31, 2019, NIPSCO's projected jurisdictional operating income from its electric utility operations at current rates was shown by NIPSCO to be as follows:

Total Operating Revenue		$1,527,202,346
Less Total Fuel Costs	$407,025,357	
Gross Margin		$1,120,176,989
Less Total Operations and Maintenance Expense	$495,797,094	
Less Total Depreciation Expense	$269,915,038	
Less Total Amortization Expense	$43,180,556	
Less Total Taxes Other Than Income	$39,273,167	
Less Federal and State Taxes	$35,787,103	
Total Operating Expenses including Income Taxes		$883,952,958
Net Operating Income		$236,224,031

Petitioner's Attachment 4-A-S2-S.[44] The evidence of record supports the conclusion that NIPSCO's current rates and charges are unjust, unreasonable, and inconsistent with the public interest and that NIPSCO should be authorized to adjust its rates so as to permit the provision of reasonably adequate service and facilities at just and reasonable rates.

(8) Rate Level to be Authorized. Based on the Revenue Settlement and the Commission's risk reduction transition adjustment, NIPSCO should be authorized a fair rate of return of no more than $268,330,735 yielding an overall return of 6.52%, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding; (2) NIPSCO's proposed capital structure adjusted for the Commission's risk reduction transition adjustment, which prescribes an authorized ROE of 9.75%.

Based on the foregoing, the Commission finds that NIPSCO should be authorized rates projected to produce operating revenue for Step 1 and Step 2, as follows:

	Step 1	Step 2
Operating Revenues	$1,453,163,108	$1,478,289,992
Operating Expenses and Taxes		
Fuel Costs	$321,765,239	$321,765,239
Operating & Maintenance Expenses	$489,075,656	489,128,103
Depreciation Expense	$261,122,046	$269,915,038

[44] The values shown were provided in support of Petitioner's projected Step 2 rates to be based on plant in service and capital structure as of December 31, 2019, and thereby correspond to the close of Petitioner's 2019 Forward Test Year.

Amortization Expense	$39,292,177	$43,180,556
Taxes Other Than Income Taxes	$39,184,168	$39,214,372
Income Taxes	$46,342,112	$46,755,949
Total Operating Expenses and Taxes	$1,196,781,399	$1,209,959,257
Projected Net Operating Income	$256,381,710	$268,330,735

(9) Conclusion Regarding Revenue Settlement. Based upon the evidence of record, we find and conclude that the Revenue Settlement presents a balanced and comprehensive resolution of the revenue and other miscellaneous issues set out above. Therefore, the Commission approves the Revenue Settlement's terms and conditions, exclusive of the agreed-upon ROE, as reasonable, supported by substantial evidence, and in the public interest.

(10) Effect of Settlement. With regard to future citation of this Order, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC 3/19/1997).

E. Electric Service Tariff and Standard Contract. NIPSCO witness Westerhausen sponsored NIPSCO's Proposed Tariff,[45] Agreement for Electric Service for Rates 824, 825, 832, 833, and 844,[46] and Agreement for Electric Service for Rate 831 and Rider 876.[47] The facts that affect the specific schedule charge amounts have been discussed throughout this Order and shall be incorporated in the compliance filing to this Order. With the exception of: (1) NIPSCO's proposed changes to reflect its proposed industrial service structure; (2) NIPSCO's proposed updates to its FAC Tracker; and (3) NIPSCO's proposal to discontinue its ECR Mechanism, no party objected to NIPSCO's Proposed Tariff and Standard Contract for Electric Service. Based upon the evidence of record, the uncontested proposals for NIPSCO's Proposed Tariff and Standard Contract for Electric Service, are approved as proposed by NIPSCO.

Based upon the evidence of record and consistent with our approval of the Rate 831 Settlement, NIPSCO's proposed Rates 831, 832, and 833, and Riders 881 and 882 reflecting its industrial service structure are approved.

Mr. Westerhausen explained that the FAC Tracker had been revised: (1) to update the average cost of fuel in base rates in this proceeding; (2) due to the elimination of Rider 775, 25% of costs associated with credits paid for interruptible and/or curtailable load under Rider 775 will no longer be passed through the FAC Tracker; and (3) to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider. The OUCC recommended that the Commission continue allowing the OUCC and intervenors to file their testimony and report 35 days after NIPSCO files its FAC application and testimony. No party opposed that

[45] Attachment 19-A, as corrected (January 2, 2019, January 22, 2019, and June 7, 2019) and revised in Attachment 19-R-A (Rate 832), Attachment 19-R-B (Rate 833), Attachment 19-R-E (Appendix A), Attachment 19-R-H (Rate 831), and Attachment 19-S2-A (Rate 831 and Riders 881 and 882).
[46] Attachment 19-R-M.
[47] Attachment 19-R-O.

recommendation and the Commission agrees to keep it in place. For purpose of NIPSCO's FAC proceedings, we find NIPSCO's base cost of fuel to be $0.026736.

With regard to NIPSCO's proposal to discontinue its ECR Mechanism, NIPSCO witness Westerhausen explained that since all of the Environmental Compliance Projects are or will be in-service and thus rolled into rate base in this case, NIPSCO is proposing to discontinue the ECR Mechanism. ICC witness Medine recommended that approval to discontinue the ECR Mechanism should only be provided if NIPSCO agrees to exclude all variable costs currently in the ECR Mechanism and in base rates from the calculation of its offer prices when bidding its units into the market. NIPSCO witness Campbell testified that NIPSCO did not include inappropriate components of its offers to MISO, nor were they imprudent with respect to its generation decision-making. He explained that the variable costs of production that are built into the agreed revenue requirement are based upon production cost modeling, which is based upon NIPSCO's variable costs of production in relation to other sources of power that are offered into the MISO market. This precise issue was raised and rejected in our April 29, 2019 Order in Cause No. 38706 FAC 122 ("FAC 122 Order"). In our FAC 122 Order, we found that NIPSCO demonstrated that its current offer strategy of its generation units into the MISO energy market was reasonable. In that order, we also found that "NIPSCO has adequately demonstrated that it 'has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]' Ind. Code § 8-1-2-42." The Commission reaches the same conclusion in this case. Based upon the evidence of record and consistent with our approval of the Revenue Settlement, NIPSCO's proposal to discontinue its ECR Mechanism is approved.

F. Accounting Relief. Besides the accounting relief requested and which we have already approved regarding the depreciation rates and estimated useful lives of generating assets, NIPSCO seeks accounting authority to defer, as a regulatory asset, discounts offered to certain customers under its EDR for recovery in a future rate case; authority to defer, as a regulatory liability, an amount equal to 100% of: (1) annual OSS margins net of expenses; and (2) back-up and maintenance demand margins, both for pass back through the RTO Tracker; and authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. No party objected to NIPSCO's requested accounting authority. Based upon the evidence of record, and consistent with our approval of the Revenue Settlement, we find that NIPSCO's request is reasonable and should be approved.

G. DSM. NIPSCO proposes to reset lost margins in its DSM tracker filing upon new, effective base rates in this proceeding to eliminate lost margins attributable to all EE measures installed prior to December 31, 2017. Ultimately, NIPSCO is seeking a neutral transition to lost margin recovery between the filing of this rate case and the operation of its DSM tracker filing. No party objected to NIPSCO's request. Based upon the evidence of record, we find that NIPSCO's request is reasonable and should be approved.

H. RTO Tracker and OSS Margin Sharing. NIPSCO proposed to update Rider 771 – Adjustment of Charges for Regional Transmission Organization to: (1) remove MISO charges and credits and collect 100% of MISO charges that are not included in the FAC through the RTO; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO; (3) remove all back-up and

maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology. No party objected to NIPSCO's request, except to the extent they objected to the allocation methodology proposed for Rate 831. Based upon the evidence of record and our approval of the Rate 831 Settlement, we find that NIPSCO's request is reasonable and should be approved.

I. Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with Commission orders. Ms. Shikany described these costs as follows: TDSIC Remand Amount in accordance with the September 23, 2015 Order on Remand in Consolidated Cause Nos. 44370/44371; TDSIC Costs in accordance with the July 12, 2016 Order in Cause No. 44733; Federally Mandated Costs in accordance with the January 29, 2014 order in Cause No. 44340, December 13, 2017 Order in Cause No. 44872, and July 12, 2017 Order in Cause No. 44889; and MATS Expenses in accordance with the October 10, 2013 Order in Cause No. 44311. Based on the evidence of record, and consistent with our approval of the Revenue Settlement, we find that NIPSCO's request is reasonable and should be approved.

29. Confidential Information. NIPSCO filed motions for protective order on October 31, 2018, February 27, 2019, March 13, 2019, and July 17, 2019, all of which were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued docket entries finding all of the information described in the motions to be preliminarily confidential, after which such information was submitted under seal. We find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION THAT:

1. The Stipulation and Settlement Agreement on Rate 831 Implementation between NIPSCO, Industrial Group, NLMK Indiana, and US Steel attached hereto is approved and adopted by the Commission, in its entirety, without change or modification.

2. The Stipulation and Settlement Agreement on Less than all the Issues between NIPSCO, Industrial Group, NLMK Indiana, US Steel, CAC, Walmart, NICTD, Sierra Club, IMUG, and the OUCC attached hereto is approved and adopted by the Commission, exclusive of the Revenue Settling Parties' agreed-upon ROE, as set forth in Finding 28.C.(4) above, which impacts the Revenue Settling Parties' agreed-upon Revenue Requirement.

3. NIPSCO is authorized to implement the authorized rate increase in two steps to be implemented as set forth in Ordering Paragraphs 4 and 5 below. Prior to implementing the rates authorized in this Order, NIPSCO shall file the tariff and applicable rate schedules under this Cause with the Commission, and such rates shall be effective subject to the Energy Division's review and agreement with the amount reflected.

4. For Step 1, NIPSCO shall file new schedules of rates and charges with the Energy

Division of the Commission based on the agreed revenue requirement as adjusted to reflect the order-approved ROE, original cost of NIPSCO's net utility plant in service, actual capital structure, and associated depreciation and amortization expense as of June 30, 2019, maintaining the amortization of the protected excess ADIT using ARAM and unprotected property using ARAM and other unprotected excess ADIT using ten years. Step 1 rates will become effective on the next billing cycle following NIPSCO's submission of its Step 1 compliance filing.

5. For Step 2, NIPSCO shall file new schedules of rates and charges with the Energy Division of the Commission based on the agreed revenue requirement, as adjusted to reflect the order-approved ROE, as of December 31, 2019, as adjusted, if necessary, to reflect the lesser of: (1) NIPSCO's forecasted test-year-end rate base as updated in NIPSCO's rebuttal evidence ($4,115,502,071); or (2) NIPSCO's certified test-year-end net plant in service as of December 31, 2019. Step 2 rates shall include the amortization of $12,170,384 per year in the revenue requirement related to the pass back of the unprotected property and other unprotected excess ADIT to customers. Step 2 rates will be certified and go into effect, subject to refund, on March 1, 2020. The OUCC and intervening parties will have 60 days from the date of certification to state any objections to NIPSCO's certified test-year-end net plant in service. If there are objections, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued-up (with carrying charges) retroactive to the date that NIPSCO's Step 2 rates became effective.

6. All schedules of rates and charges submitted under Ordering Paragraphs 4 and 5 shall be developed according to the agreed on rate design as described by the terms of the Revenue Settlement and the allocation among customer classes as described by the terms of the Rate 831 Settlement, as set forth in Finding 28.C. above.

7. The proposed IURC Electric Service Tariff, Original Volume No. 14 is approved consistent with the Rate 831 Settlement and Revenue Settlement and this Order, inclusive of the associated General Rules and Regulations and Standard Contracts.

8. NIPSCO's proposed depreciation rates are approved consistent with the Revenue Settlement and this Order.

9. NIPSCO is authorized to create a regulatory asset equal to the remaining net book value of its R.M. Schahfer Generating Units and Michigan City Generating Unit at the date of each unit's retirement to be amortized through December 31, 2032 consistent with the Revenue Settlement and this Order.

10. NIPSCO is authorized: (1) to defer as a regulatory asset, discounts offered to certain customers under its Economic Development Rider for recovery in a future rate case; and (2) to defer as a regulatory liability, an amount equal to 100% of annual off-system sales margins net of expenses and back-up and maintenance demand margins, both for pass back through the RTO Tracker.

11. The information submitted under seal in this Cause pursuant to motions for protective orders is determined to be confidential and exempt from public access and disclosure

pursuant to Ind. Code § 24-2-3-2 and § 5-14-3-4.

12. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:

APPROVED: DEC 4 2019

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M. Becerra
Secretary of the Commission

FILED
April 26, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	CAUSE NO. 45159

SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT ON LESS THAN ALL THE ISSUES

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, on behalf of itself and NIPSCO Industrial Group; NLMK Indiana; United States Steel Corporation; the Citizens Action Coalition of Indiana, Inc.; Walmart Inc.; Northern Indiana Commuter Transportation District; Sierra Club; and the Indiana Office of Utility Consumer Counselor (collectively the "Settling Parties"),

respectfully submits the attached Stipulation and Settlement Agreement on Less Than all the Issues (the "Settlement Agreement").

The Settlement Agreement resolves the revenue requirements issues and other miscellaneous issues. The Settling Parties are continuing to work to see if any other parties will join the Settlement Agreement. The Settling Parties are also continuing discussions regarding revenue allocation and Rate 831 rate design to attempt to reach resolution. The Settling Parties will provide the Commission with a status report on or before April 30, 2019 regarding the status of settlement negotiations on revenue allocation and Rate 831 rate design and to advise if any additional parties have agreed to join the Settlement Agreement.

Respectfully submitted on behalf of the Settling Parties,

Claudia J. Earls (No. 8468-49)
NiSource Corporate Services – Legal
150 West Market Street, Suite 600
Indianapolis, IN 46204
Telephone: (317) 684-4923
Facsimile: (317) 684-4918
cjearls@nisource.com

Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic transmission this 26th day of April, 2019 to:

OUCC
Jeffrey M. Reed
Office of Utility Consumer Counselor
115 W. Washington Street
Suite 1500 South
Indianapolis, Indiana 46204
jreed@oucc.in.gov
infomgt@oucc.in.gov

NIPSCO INDUSTRIAL GROUP
Bette J. Dodd
Todd A. Richardson
Joseph P. Rompala
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
bdodd@lewis-kappes.com
trichardson@lewis-kappes.com
jrompala@lewis-kappes.com

US STEEL
Nikki G. Shoultz
Kristina Kern Wheeler
Jeffery A. Earl
Bose McKinney & Evans LLP
111 Monument Circle, Suite 2700
Indianapolis, Indiana 46204
nshoultz@boselaw.com
kwheeler@boselaw.com
jearl@boselaw.com

INDIANA MUNICIPAL UTILITY GROUP
Robert M. Glennon
Robert Glennon & Assoc., P.C.
3697 N. Co. Rd. 500 E
Danville, Indiana 46122
robertglennonlaw@gmail.com

NLMK INDIANA
Anne E. Becker
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
abecker@lewis-kappes.com

NLMK INDIANA
James W. Brew
Stone Mattheis Xenopoulos & Brew
1025 Thomas Jefferson St., NW,
9th Floor, West, Tower,
Washington, DC 20007
jbrew@smxblaw.com

CITIZENS ACTION COALITION
Jennifer A. Washburn
Margo L. Tucker
Citizens Action Coalition
1915 West 18th Street, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org
mtucker@citact.org

Cassandra McCrae
Raghu Murthy
Earthjustice
1617 John F. Kennedy Blvd., Suite 1130
Philadelphia, Pennsylvania 19103
cmccrae@earthjustice.org
rmurthy@earthjustice.org

Thomas Cmar
Earthjustice
1010 Lake Street, Suite 200
Oak Park, Illinois 60301
tcmar@earthjustice.org

WALMART
Eric E. Kinder
Spilman Thomas & Battle, PLLC
300 Kanawha Boulevard, East
P.O. Box 273
Charleston, West Virginia 25321
ekinder@spilmanlaw.com

Barry A. Naum
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, Pennsylvania 17050
bnaum@spilmanlaw.com

SIERRA CLUB
Kathryn A. Watson
Cantrell Strenski & Mehringer, LLP
150 West Market Street, Suite 800
Indianapolis, Indiana 46204
kwatson@csmlawfirm.com

Tony Mendoza
Sierra Club
2101 Webster St., 13th Floor
Oakland, California 94612
Tony.mendoza@sierraclub.org

Casey Roberts
Sierra Club
1536 Wynkoop St., Suite 312
Denver, Colorado 80202
Casey.roberts@sierraclub.org

INDIANA COAL COUNCIL
Robert L. Hartley
Carly J. Tebelman
Frost Brown Todd LLC
201 N. Illinois Street, Suite 1900
P.O. Box 44961
Indianapolis, Indiana 46244-0961
rhartley@fbtlaw.com
ctebelman@fbtlaw.com

PEABODY COALSALES, LLC
Joshua A. Claybourn
Chad Sullivan
Jackson Kelly PLLC
221 NW Fifth Street
P.O. Box 1507
Evansville, Indiana 47706
jclaybourn@jacksonkelly.com
cjsullivan@jacksonkelly.com

MODERN FORGE
Alan M. Hux
Taft Stettinius & Hollister, LLP
One Indiana Square, Suite 3500
Indianapolis, Indiana 46204
ahux@taftlaw.com

ICARE
Meghan E. Griffiths
Jennifer A. Ferri
Jackson Walker LLP
100 Congress Ave., Suite 1100
Austin, Texas 78701
mgriffiths@jw.com
jferri@jw.com

Robert L. Hartley
Frost Brown Todd LLC
201 N. Illinois Street, Suite 1900
Indianapolis, Indiana 46244
rhartley@fbtlaw.com

LAPORTE COUNTY
Shaw R. Friedman
Friedman & Associates, P.C.
705 Lincolnway
LaPorte, Indiana 46350
sfriedman.associates@frontier.com

Keith L. Beall
Beall & Beall
13238 Snow Owl Dr., Ste. A
Carmel, Indiana 46033
kbeall@indy.rr.com

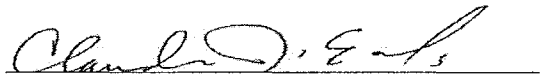
RACKERS
Dennis Rackers
275 E. 125th Pl
Crown Point, IN 46307
dsrasdf@gmail.com

UNITED STEELWORKERS
Anthony Alfano
United Steelworkers
1301 Texas St., 2nd Floor
Gary, Indiana 46402
aalfano@usw.org

NICTD

L. Charles Lukmann, III
Connor H. Nolan
Harris Welsh & Lukmann
107 Broadway
Chesterton, Indiana 46304
clukmann@hwllaw.com
cnolan@hwllaw.com

James A.L. Buddenbaum
Aleasha J. Boling
Parr Richey Frandsen Patterson Kruse LLP
251 N. Illinois Street, Suite 1800
Indianapolis, Indiana 46204
jbuddenbaum@parrlaw.com
aboling@parrlaw.com



Claudia J. Earls

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	**CAUSE NO. 45159**

STIPULATION AND SETTLEMENT AGREEMENT ON LESS THAN ALL THE ISSUES

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 25th day of April, 2019, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); the NIPSCO Industrial Group ("Industrial Group");[1] NLMK Indiana; United States Steel Corporation; the Citizens Action Coalition of Indiana, Inc.; Walmart Inc.; Northern Indiana Commuter Transportation District; Sierra Club; and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"), who stipulate and agree for purposes of settling the revenue requirements issues in this Cause that the terms and conditions set forth below represent a fair and reasonable resolution of the revenue requirement issues and other miscellaneous issues subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission

[1] The Industrial Group is comprised of Accurate Castings, Inc., ArcelorMittal USA, BP Products North America, Inc., Cargill, Inc., Enbridge Energy, Praxair, Inc., and USG Corporation.

("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein.

A. Background

1. NIPSCO's Current Rates and Charges: NIPSCO's current electric basic rates and charges were approved in the Commission's July 18, 2016 Order in Cause No. 44688 (the "44688 Rate Case Order"). The basic rates and charges approved in the 44688 Rate Case Order went into effect on September 29, 2016. Those rates and charges remain in effect today, as modified by various riders approved by the Commission from time to time; and as modified on May 1, 2018 pursuant to the Commission's January 3, 2018 Order in Cause No. 45032 to reflect the reduction in the federal income tax rate from 35 percent to 21 percent in accordance with the Tax Cut and Jobs Act of 2017 ("TCJA").[2]

2. NIPSCO's Current Depreciation and Accrual Rates: NIPSCO's current common and electric depreciation rates were approved in the Commission's 44688 Rate Case Order. The Commission's Orders in Cause Nos. 44012 and 44340 approved specific depreciation accrual rates to be applied to plant and equipment identified in those proceedings. For other items of property, NIPSCO's current depreciation accrual rates were approved in the 44688 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings: NIPSCO files a quarterly FAC proceeding in accordance with Indiana Code §8-1-2-42(d) in Cause No. 38706-FAC-XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs. In accordance with Rider 770 – Adjustment of Charges for Cost of Fuel

[2] The Commission approved NIPSCO's 30-Day Filing No. 50167 on April 25, 2018.

Rider, 25% of costs associated with credits paid for interruptible and/or curtailable load under Rider 775 – Interruptible Industrial Service Rider are also recovered in quarterly FAC proceedings. Historically, NIPSCO has agreed that the OUCC and other interested parties should have thirty-five (35) days to review NIPSCO's FAC filings and NIPSCO has agreed to continue that practice.

4. NIPSCO's Tracking Mechanisms: In coordination with its FAC proceedings, NIPSCO files semi-annual proceedings in: (a) Cause No. 44156-RTO-XX to recover costs associated with MISO non-fuel costs and revenues and to provide for off-system sales sharing through its Rider 771 – Adjustment of Charges for Regional Transmission Organization ("RTO Tracker") and Appendix C – Regional Transmission Organization Adjustment Factor approved by the Commission in its 44688 Rate Case Order; and (b) Cause No. 44155-RA-XX to recover prudently incurred capacity costs through its Rider 774 – Adjustment of Charges for Resource Adequacy ("RA Tracker") and Appendix F – Resource Adequacy Adjustment Factor approved by the Commission in its 44688 Rate Case Order.[3] In addition, pursuant to Rider 774, 75% of costs associated with credits paid for interruptible load under Rider 775 are recovered through the RA Tracker.

[3] In its August 25, 2010 Order in Cause No. 43526, the Commission found that NIPSCO's MISO non-fuel costs and revenues and off system sales sharing should be included in one mechanism designated as the RTO Adjustment. In its December 21, 2011 Order in Cause No. 43969, the Commission approved the implementation of the RTO Adjustment approved in Cause No. 43526 by approving Rider 671 and Appendix C. In the 44688 Rate Case Order, the Commission approved NIPSCO's request for authority to defer, as a regulatory asset or liability, an amount equal to 50% of annual off system sales margins above or below the level of off-system sales margins included in the test year for recovery through the RTO tracker.

In its August 25, 2010 Order in Cause No. 43526, the Commission found that NIPSCO's prudently incurred capacity should be recovered through the Resource Adequacy or RA Adjustment. In its December 21, 2011 Order in Cause No. 43969, the Commission approved the implementation of the RA Adjustment approved in Cause No. 43526 by approving Rider 674 and Appendix F.

NIPSCO files semi-annual proceedings in Cause No. 42150-ECR-XX to recover costs associated with qualified pollution control property, clean coal technology and clean energy projects to allow NIPSCO to comply with various environmental obligations through its Rider 772 – Adjustment of Charges for Environmental Cost Recovery Mechanism ("ECRM Tracker") and Appendix D — Environmental Cost Recovery Mechanism Factor approved by the Commission in its 44688 Rate Case Order.[4]

NIPSCO files an annual proceeding in Cause No. 43618-DSM-XX to recover program costs and lost revenues associated with approved demand side management and energy efficiency programs through its Rider 783 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) and Appendix G – Demand Side Management Adjustment Mechanism (DSMA) Factor initially approved by the Commission in its May 25, 2011 Order in Cause No. 43618. In its February 27, 2017 Order in Cause No. 43618-DSM-11, the Commission approved a modification to NIPSCO's Rider 783 to move from a semi-annual to annual filing.

NIPSCO files an annual proceeding in Cause No. 44198-GPR-XX to revise the Green Power Rider rate set forth in its Rider 786 – Green Power Rider and Appendix H – Green Power Rider Rate. The initial tracking mechanism was approved in the Commission's December 19, 2012 Order in Cause No. 44198. In its December 28, 2016 Order in Cause No. 44198-GPR-8 the Commission approved a modification to NIPSCO's Rider 786 to move from a semi-annual to annual filing.

---

[4] The Commission approved two tracking mechanisms in its November 26, 2002 Order in Cause No. 42150 by approving Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism and Appendix D – Environmental Cost Recovery Mechanism Factor and Rider 673 □ Adjustment of Charges for Environmental Expense Recovery Mechanism and Appendix E – Environmental Expense Recovery Mechanism Factor. The Commission subsequently approved the consolidation of Riders 672 and 673 in its 44688 Rate Case Order.

NIPSCO files a semi-annual proceeding in Cause No. 44340-FMCA-XX to recover federally mandated costs through its Rider 787 – Adjustment of Charges for Federally Mandated Costs ("FCMA") and Appendix I – Federally Mandated Cost Adjustment Factor. The initial tracking mechanism was approved in the Commission's January 29, 2014 Order in Cause No. 44340.

NIPSCO files a semi-annual proceeding in Cause No. 44733-TDSIC-XX to recover 80% of eligible and approved capital expenditures and transmission, distribution, and storage system improvement charge costs for eligible projects through Rider 788 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix J – Transmission, Distribution and Storage System Improvement Charge. The initial tracking mechanism was approved in the Commission's February 17, 2014 Order in Cause No. 44371.

5. This Proceeding: On October 31, 2018, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to increase its retail rates and charges for electric utility service through the phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders; (3) approving revised common and electric depreciation rates applicable to electric plant in service; (4) approving necessary and appropriate accounting relief; (5) approving a new service structure for industrial rates ("Rate 831"); (6) authorizing NIPSCO to implement temporary rates; and (7) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on October 31, 2018. On February 13, 2019, the OUCC and intervenors filed their

respective cases-in-chief and on March 15, 2019, NIPSCO filed its rebuttal testimony and exhibits and several intervenors filed cross-answering testimony and exhibits.

As discussed within NIPSCO's Verified Petition, and the testimony of various parties including NIPSCO, this rate case filing was driven by several developments subsequent to the 44688 Rate Case Order. First, NIPSCO needed to address unresolved impacts related to the TCJA, particularly the return of excess Accumulated Deferred Income Tax ("ADIT"). Second, NIPSCO sought to modify its depreciation rates and cost recovery in rates for NIPSCO's coal-fired generating assets to reflect the useful life of those assets as reflected in NIPSCO's Integrated Resource Plan. Third, as part of an alternative regulatory plan under Ind. Code §8-1-2.5-6, NIPSCO proposed to modify its industrial service rate structure to respond to a changing energy landscape and economic conditions that directly impact its largest customers.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income:

(a) Revenue Requirement: The Settling Parties agree that NIPSCO's base rates will be designed to produce $1,482,166,740 prior to application of surviving Riders. This Revenue Requirement is a decrease of approximately $63.648 Million from the amount originally requested by NIPSCO. The Settling Parties agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below, and a $2,000,000 decrease to NIPSCO's proposed O&M Expense.

(b) Net Operating Income: The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.1(a) above results in a proposed authorized net operating income ("NOI") of $271,211,585.

2. Fair Value Rate Base, Capital Structure, and Fair Return:

(a) Fair Value Rate Base: The Settling Parties agree that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based on this Agreement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon:

(i) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding;

(ii) NIPSCO's proposed capital structure; and

(iii) an authorized return on equity ("ROE") of 9.90%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.90% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	Dollars	Cost %	WACC %
Common Equity	$2,864,884,714	9.90%	4.74%
Long-Term Debt	$2,151,351,378	4.97%	1.79%
Customer Deposits	$71,453,491	4.91%	0.06%
Deferred Income Taxes	$1,266,429,454	0.00%	0.00%
Post-Retirement Liability	$66,142,914	0.00%	0.00%
Prepaid Pension Asset	$(435,272,223)	0.00%	0.00%
Post-1970 ITC	$2,014,831	8.30%	0.00%
Totals	**$5,987,004,559**		**6.59%**

3. Depreciation and Amortization Expense:

(a) Depreciation Expense: The Settling Parties agree that the depreciation accrual rates recommended by NIPSCO in this proceeding should be approved with the following exceptions:

(i) the amortization period for retired coal-fired generating units as described in NIPSCO's case-in-chief shall conclude in 2032, which presumes the retirement of the R.M. Schahfer ("Schahfer") Generating Units in 2023 and the Michigan City Generating Unit in 2028; and

(ii) annual depreciation expense shall be adjusted to reflect the removal of $26 Million in contingency expense included in demolition costs, as proposed by Industrial Group Witness Gorman.

(b) Amortization Expense: The Settling Parties agree that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding with the following exception:

(i) the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC 7 Year Plan, FMCA, MATs, EDR and Electric Rate Case Expense of seven (7) years.

If not already addressed by an intervening base rate case order, after the completion of the seven (7) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(c) Revenue Credit: NIPSCO agrees to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City Generating Units reflected in NIPSCO's rate base at the time a Final Order is issued in this proceeding and the actual investment amount adjusted for depreciation as outlined in OUCC Witness Blakely's direct testimony. NIPSCO agrees to implement the credit upon the retirement of the Generating Units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. The credit will be limited to the net plant investment value of the Schahfer and Michigan City Generating Units embedded in the base rates established in this Cause and the associated accumulated

depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in paragraph B.1(a), and (2) the NOI established in paragraph B.1(b) for purposes of its earnings test. NIPSCO agrees to hold annual pre-filing meetings preceding the 30 day compliance filing with interested stakeholders.

4. Tax Cut and Jobs Act:

(a) Protected and Net Operating Loss Excess ADIT: The Settling Parties agree that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in NIPSCO's revenue requirement at the average rate assumption method ("ARAM"), estimated at the time of this Agreement to be 26 years.

5. Unprotected and Other Excess ADIT: The Settling Parties agree that NIPSCO's Unprotected and Other Excess ADIT balance, totaled approximately $137,789,071 as of December 31, 2017. NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. If not already addressed by an intervening base rate case order, after the completion of the ten (10) year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization.

6. Phase II Rate Implementation:

(a) Phase II Rates Subject to Refund: Phase II rates shall be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agrees it shall not be permitted to include in rate base for Phase II rates plant in excess of the amount or value of plant projected in this Cause. The Settling Parties agree that Phase II rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Phase II rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019 and calculate the Phase II rates using those certified figures. For purposes of this Agreement, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies and that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2019. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a

hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Phase II rates were put into place.

7. Revenue Allocation:

(a) The Settling Parties agree to continue discussions regarding revenue allocation and Rate 831 rate design to attempt to reach resolution and also agree to provide the Commission with a status report on or before April 30, 2019 regarding the status of settlement negotiations on revenue allocation and Rate 831 rate design.

8. Rate Design:

(a) The Settling Parties have agreed on the following issues related to rate design.

(i) Residential Customer Charge: The Settling Parties agree that rates should be designed with the Residential Customer Charge set at $13.50/month.

(ii) Rate 830: The Settling Parties agree that as proposed in Industrial Group Witness Phillips' Direct Testimony and NIPSCO Witness Westerhausen's Rebuttal Testimony, Rate 830 shall be split into Rates 832 and 833 which shall reflect the current structure of Rates 732 and 733, and

provide for backup and maintenance provisions reflected in current Rider 776.

(iii) Rate 844: The Settling Parties agree that Rate 844 shall see no increase in its base rates resulting from this proceeding given its importance to Northwest Indiana in providing public transportation between South Bend and Chicago.

9. Tariff Changes:

(a) Trackers and Riders:

(i) NIPSCO agrees to flow through the RTO Tracker 100% of all margins, including any net losses, from off-system sales, down to zero.

(ii) NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years.

(iii) The Settling Parties agree that NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief.

10. Low Income Program Commitment:

(a) NIPSCO commits to seek approval of a voluntary low income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process NIPSCO has already established with

NIPSCO and interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

C. Procedural Aspects and Presentation of the Agreement

1. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the simplification and minimization of issues to be presented in the proceeding.

2. The Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding, and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

3. If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of material condition deemed unacceptable to any Settling Party. If the Commission does not approve

the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications. In the event the Agreement is withdrawn, the Settling Parties will request an Attorney's Conference to be convened to establish a procedural schedule for the continued litigation of this proceeding.

4. The Settling Parties agree that this Agreement and each term, condition, amount, methodology, and exclusion contained herein reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and the Final Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

5. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Agreement as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it, without objection.

6. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

7. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement and the Settling Parties shall not support any appeal of any portion of the of Final Order by any person not a party to this Agreement.

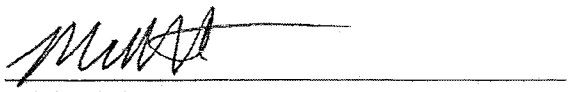
8. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

9. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 25th day of April, 2019.

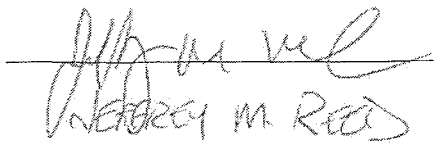
[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC



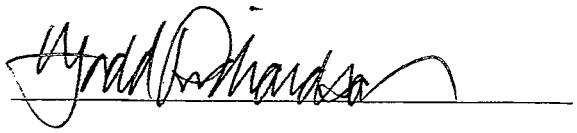
Michael Hooper
Senior Vice President
Regulatory, Legislative Affairs and Strategy

Indiana Office of Utility Consumer Counselor

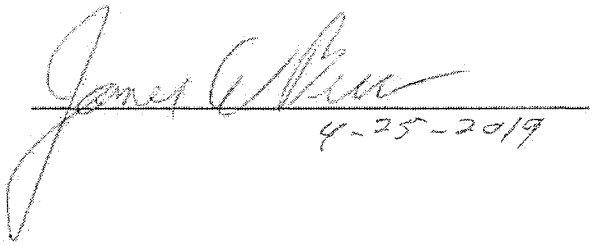


Jeffrey M. Reed

NIPSCO Industrial Group



NLMK Indiana



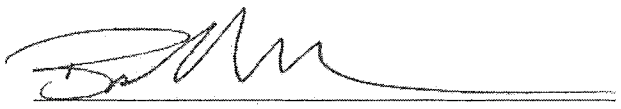
United States Steel Corporation



Citizens Action Coalition of Indiana, Inc.



Walmart Inc.



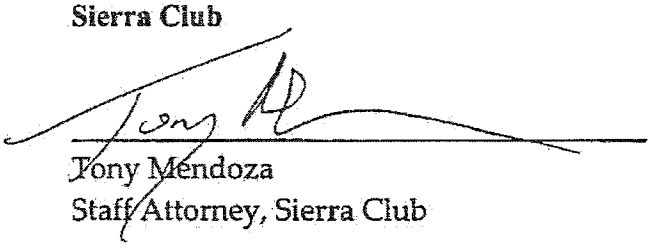
Northern Indiana Commuter Transportation District

By _____

JAMES A. L. BUDDENBAUM

One of Its Attorneys

Sierra Club



Tony Mendoza
Staff Attorney, Sierra Club

FILED
May 17, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	CAUSE NO. 45159

SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831 IMPLEMENTATION

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, on behalf of itself and NIPSCO Industrial Group; NLMK Indiana; and United States Steel Corporation (collectively the "Rate 831 Settling Parties"), respectfully submits the attached Stipulation and Settlement Agreement on Rate 831 Implementation (the Rate 831 Implementation Agreement"). The Rate 831 Implementation Agreement resolves the implementation of Rate 831, including

the proposed revenue allocation to Rate 831. The Rate 831 Settling Parties would propose that any party wishing to file testimony in response to the Rate 831 Implementation Agreement do so by June 7, 2019, to allow for the remainder of the procedural schedule to remain unchanged.

Respectfully submitted on behalf of the Rate 831 Settling Parties,

Claudia J. Earls (No. 8468-49)
NiSource Corporate Services – Legal
150 West Market Street, Suite 600
Indianapolis, IN 46204
Telephone: (317) 684-4923
Facsimile: (317) 684-4918
cjearls@nisource.com

Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic transmission this 17th day of May, 2019 to:

OUCC
Jeffrey M. Reed
Office of Utility Consumer Counselor
115 W. Washington Street
Suite 1500 South
Indianapolis, Indiana 46204
jreed@oucc.in.gov
infomgt@oucc.in.gov

NIPSCO INDUSTRIAL GROUP
Bette J. Dodd
Todd A. Richardson
Joseph P. Rompala
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
bdodd@lewis-kappes.com
trichardson@lewis-kappes.com
jrompala@lewis-kappes.com

US STEEL
Nikki G. Shoultz
Kristina Kern Wheeler
Jeffery A. Earl
Bose McKinney & Evans LLP
111 Monument Circle, Suite 2700
Indianapolis, Indiana 46204
nshoultz@boselaw.com
kwheeler@boselaw.com
jearl@boselaw.com

INDIANA MUNICIPAL UTILITY GROUP
Robert M. Glennon
Robert Glennon & Assoc., P.C.
3697 N. Co. Rd. 500 E
Danville, Indiana 46122
robertglennonlaw@gmail.com

NLMK INDIANA
Anne E. Becker
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
abecker@lewis-kappes.com

NLMK INDIANA
James W. Brew
Stone Mattheis Xenopoulos & Brew
1025 Thomas Jefferson St., NW,
9th Floor, West, Tower,
Washington, DC 20007
jbrew@smxblaw.com

CITIZENS ACTION COALITION
Jennifer A. Washburn
Margo L. Tucker
Citizens Action Coalition
1915 West 18th Street, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org
mtucker@citact.org

Cassandra McCrae
Raghu Murthy
Earthjustice
1617 John F. Kennedy Blvd., Suite 1130
Philadelphia, Pennsylvania 19103
cmccrae@earthjustice.org
rmurthy@earthjustice.org

Thomas Cmar
Earthjustice
1010 Lake Street, Suite 200
Oak Park, Illinois 60301
tcmar@earthjustice.org

WALMART
Eric E. Kinder
Spilman Thomas & Battle, PLLC
300 Kanawha Boulevard, East
P.O. Box 273
Charleston, West Virginia 25321
ekinder@spilmanlaw.com

Barry A. Naum
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, Pennsylvania 17050
bnaum@spilmanlaw.com

SIERRA CLUB
Kathryn A. Watson
Cantrell Strenski & Mehringer, LLP
150 West Market Street, Suite 800
Indianapolis, Indiana 46204
kwatson@csmlawfirm.com

Tony Mendoza
Sierra Club
2101 Webster St., 13th Floor
Oakland, California 94612
Tony.mendoza@sierraclub.org

Casey Roberts
Sierra Club
1536 Wynkoop St., Suite 312
Denver, Colorado 80202
Casey.roberts@sierraclub.org

INDIANA COAL COUNCIL
Robert L. Hartley
Carly J. Tebelman
Frost Brown Todd LLC
201 N. Illinois Street, Suite 1900
P.O. Box 44961
Indianapolis, Indiana 46244-0961
rhartley@fbtlaw.com
ctebelman@fbtlaw.com

PEABODY COALSALES, LLC
Joshua A. Claybourn
Chad Sullivan
Jackson Kelly PLLC
221 NW Fifth Street
P.O. Box 1507
Evansville, Indiana 47706
jclaybourn@jacksonkelly.com
cjsullivan@jacksonkelly.com

MODERN FORGE
Alan M. Hux
Taft Stettinius & Hollister, LLP
One Indiana Square, Suite 3500
Indianapolis, Indiana 46204
ahux@taftlaw.com

ICARE
Meghan E. Griffiths
Jennifer A. Ferri
Jackson Walker LLP
100 Congress Ave., Suite 1100
Austin, Texas 78701
mgriffiths@jw.com
jferri@jw.com

Robert L. Hartley
Frost Brown Todd LLC
201 N. Illinois Street, Suite 1900
Indianapolis, Indiana 46244
rhartley@fbtlaw.com

LAPORTE COUNTY
Shaw R. Friedman
Friedman & Associates, P.C.
705 Lincolnway
LaPorte, Indiana 46350
sfriedman.associates@frontier.com

Keith L. Beall
Beall & Beall
13238 Snow Owl Dr., Ste. A
Carmel, Indiana 46033
kbeall@indy.rr.com

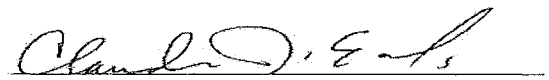
RACKERS
Dennis Rackers
275 E. 125th Pl
Crown Point, IN 46307
dsrasdf@gmail.com

UNITED STEELWORKERS
Anthony Alfano
United Steelworkers
1301 Texas St., 2nd Floor
Gary, Indiana 46402
aalfano@usw.org

NICTD

L. Charles Lukmann, III
Connor H. Nolan
Harris Welsh & Lukmann
107 Broadway
Chesterton, Indiana 46304
clukmann@hwllaw.com
cnolan@hwllaw.com

James A.L. Buddenbaum
Aleasha J. Boling
Parr Richey Frandsen Patterson Kruse LLP
251 N. Illinois Street, Suite 1800
Indianapolis, Indiana 46204
jbuddenbaum@parrlaw.com
aboling@parrlaw.com



Claudia J. Earls

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND, IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	**CAUSE NO. 45159**

STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831 IMPLEMENTATION

This Stipulation and Settlement Agreement on Rate 831 Implementation ("Rate 831 Implementation Agreement") is entered into this 17th day of May, 2019, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); the NIPSCO Industrial Group[1] ("Industrial Group"); NLMK Indiana ("NLMK");[2] and United States Steel Corporation ("US. Steel") (collectively the "Rate 831 Settling Parties"), who stipulate and agree for purposes of settling issues related to Rate 831, presented in this Cause, that the terms and conditions set forth below represent a fair and reasonable resolution subject to incorporation into a Final Order of the Indiana Utility Regulatory

[1] The Industrial Group is comprised of Accurate Castings, Inc., ArcelorMittal USA, BP Products North America, Inc., Cargill, Inc, Enbridge Energy, Praxair, Inc., and USG Corporation.

[2] NLMK joins in and supports this Rate 831 Implementation Agreement except as to paragraph C.4.

Commission ("Commission") without any modification or condition that is not acceptable to the Rate 831 Settling Parties.

A. Background

WHEREAS, NIPSCO filed a Verified Petition initiating this Cause on October 31, 2018 requesting, among other relief, approval of an Alternative Regulatory Plan pursuant to Indiana Code §8-1-2.5-6 that would facilitate a new service structure for industrial rates ("Rate 831") to address a changing energy landscape;

WHEREAS, the Rate 831 Settling Parties filed testimony explaining the operation of Rate 831 and supporting the need for Rate 831 to preserve NIPSCO's large industrial load, to retain the contribution of such load to fixed production costs, and support NIPSCO's resource planning;

WHEREAS, the Rate 831 Settling Parties filed testimony supporting the allocation methodology proposed by NIPSCO which would have produced cost-of-service rates for customers on Rate 831 while preserving a sizable subsidy for customers on Rate 811;

WHEREAS, the Rate 831 Settling Parties and other parties, including the Indiana Office of Utility Consumer Counselor, entered into and filed a Stipulation and Settlement Agreement On Less than All the Issues ("Revenue Settlement") with the Commission on April 26, 2019 which, among other matters, decreased NIPSCO's proposed revenue requirement by approximately $63.648 Million from the amount originally requested by NIPSCO;

WHEREAS, the Revenue Settlement indicated that parties would continue discussions in an effort to resolve revenue allocation and issues related to Rate 831;

WHEREAS, after negotiations conducted prior to and after the filing of the Revenue Settlement, the parties have been unable to resolve their differences on revenue allocation and issues related to Rate 831;

WHEREAS, the Rate 831 Settling Parties have been able to reach mutual agreement on issues related to Rate 831 implementation between and among themselves including rate design which will obviate the need for additional proceedings on such issues, including the Step 2 True Up, and wish to present the other parties and the Commission with an agreement to be considered as in the public interest for approval without modification;

NOW, THEREFORE, the Rate 831 Settling Parties agree to the following:

B. Settlement Terms

1. Allocation: The Rate 831 Settling Parties[3] agree that NIPSCO's cost of service study should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 megawatts. The Rate 831 Settling Parties agree that $149.438 Million (exclusive of approximately $2.827 Million in "other revenues") shall be allocated to Rate 831.

[3] US Steel submitted testimony in this Cause only related to Rate 831, and thus supports the settlement cost of service study as it relates to the rates, charges and trackers related to Rate 831, and takes no position on the remaining rate design.

2. Tracker Allocations:

a. The Rate 831 Settling Parties agree that Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (updated for the settlement revenue requirement and the adjustment for Rate 844), shall be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms.

b. The Rate 831 Settling Parties agree that Rate 831 Implementation Agreement Exhibit B, which is Attachment 19-R-E to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (with no changes), sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism.

c. For the purposes of recovery of any approved capital transmission, distribution, and storage system improvement charge ("TDSIC") expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (updated with the settlement revenue requirement) reflect the allocation factors for TDSIC purposes.

3. Rate 831 Rate Design:

a. Except as otherwise provided herein, the Rate 831 Settling Parties agree that Rate 831 shall be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in B.1., above.

b. The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the cost of service study presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in B.1., above.

c. For purposes of the "Adjacent Affiliate Qualified Facility Premise Transmission Charge" the Rate 831 Settling Parties agree that the provision shall be amended by adding the following language: " If the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period."

d. The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial 5-year contract is set forth in Rate 831 Implementation Agreement Confidential Exhibit C. The Rate 831 Settling Parties agree that the Tier 1 subscriptions

reflected in Rate 831 Implementation Agreement Confidential Exhibit C shall be binding upon each customer in the event of the approval of this Agreement without modification.

e. The Rate 831 Settling Parties agree that a transition period, lasting from the date on which Phase I rates become effective until June 1, 2020, shall provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and capacity needs. The Rate 831 Settling Parties agree that the terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

C. Procedural Aspects and Presentation of the Agreement

1. The Rate 831 Settling Parties acknowledge that a significant motivation to enter into this Rate 831 Implementation Agreement is the expectation that, if the Commission finds this Agreement to be reasonable and in the public interest, a Final Order approving the Agreement and authorizing the implementation of the Rate 831 service structure will be effective immediately, without the need for a Stage 2 True Up proceeding. The Rate 831 Settling Parties have spent considerable and valuable time reviewing data and negotiating the Agreement in an effort to eliminate time consuming and costly litigation. The Rate 831 Settling Parties agree to request that the Commission review this Agreement within the existing procedural schedule, and that if the Commission finds the Agreement to be reasonable and in the public interest, to approve the Agreement without any material modification in sufficient time to allow the Rate 831

service structure to be implemented contemporaneously with the all other changes in rates and charges.

2. The Rate 831 Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding, and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

3. If the Agreement is not approved in its entirety by the Commission, the Rate 831 Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding. Moreover, the concurrence of the Rate 831 Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of material condition deemed unacceptable to any Settling Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications.

4. In the event the Commission rejects this Settlement Agreement or the Alternative Regulatory Plan for Rate 831, or makes modifications in the Rate 831 allocation or design (collectively "831 Rejection"), which results in the six largest industrial customers being unable or unwilling to subscribe to the total megawatts included on Rate 831 Implementation Agreement Confidential Exhibit C under the proposed design, the Settling Parties agree that further proceedings in this Cause are

appropriate. In the event of 831 Rejection, the Settling Parties propose to notify the Commission so that a procedural schedule may be established to determine the proper rate structure for NIPSCO's largest industrial customers. The Rate 831 Settling Parties agree that the revenue requirement in the Revenue Settlement is calculated based upon NIPSCO's proposed change in its industrial service structure (i.e., establishing Rate 831). 831 Rejection would directly affect the stipulated revenue requirement, specifically the fuel and related expenses such that the revenue requirement will need to be revised and the allocated cost of service study will need to be revised, and that NIPSCO cannot implement new rates for any customer class until the additional proceeding is concluded.

5. The Rate 831 Settling Parties agree that this Agreement and each term, condition, amount, methodology, and exclusion contained herein reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Rate 831 Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and the Final Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Rate 831 Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

6. The Rate 831 Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Agreement as filed. The Rate 831 Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

7. The issuance of a Final Order by the Commission approving this Agreement without any material modification or further condition shall terminate all proceedings in this Cause.

8. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

9. The Rate 831 Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement and the Rate 831 Settling Parties shall oppose any appeal of any portion of the Final Order approving this Agreement.

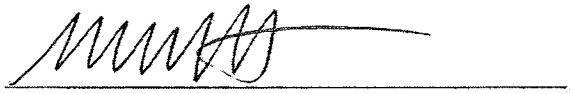
10. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

11. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 17th day of May, 2019.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

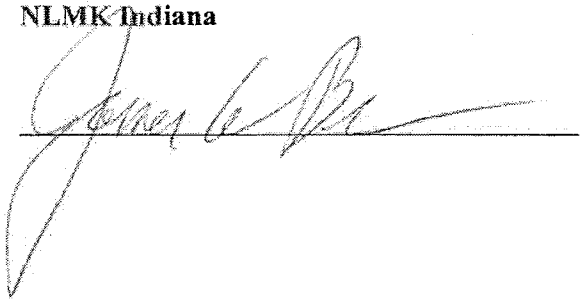


Michael Hooper
Senior Vice President
Regulatory, Legislative Affairs and Strategy

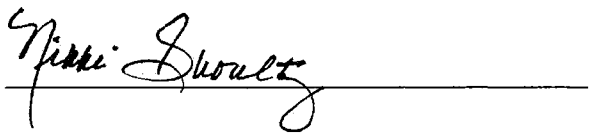
NIPSCO Industrial Group



NLMK Indiana



United States Steel Corporation



Tracker Allocators
2018 Electric Rate Case
Demand Allocation

Line	Description	Rate Class	Demand Allocators - Total Revenue	Rate 831 Tier 1 Adjustment	Revised Revenue	Resulting % Allocation on Revenue"
1	Residential	Rate 811	$ 508,397,289		$ 508,397,289	35.05%
2	C&GS Heat Pump	Rate 820	$ 914,117		$ 914,117	0.06%
3	GS Small	Rate 821	$ 253,812,406		$ 253,812,406	17.50%
4	Comml SH	Rate 822	$ 1,211,193		$ 1,211,193	0.08%
5	GS Medium	Rate 823	$ 165,705,139		$ 165,705,139	11.42%
6	GS Large	Rate 824	$ 207,833,587		$ 207,833,587	14.33%
7	Metal Melting	Rate 825	$ 7,273,007		$ 7,273,007	0.50%
8	Off-Peak Serv.	Rate 826	$ 121,033,845		$ 121,033,845	8.34%
9	Industrial Power Service - Large	Rate 831	$ -			
10	Tier 1	Tier 1	$ 152,266,583	$ (31,546,292)	$ 120,720,291	8.32%
11	Small Industrial Service - LLF	Rate 832	$ 12,790,750		$ 12,790,750	0.88%
12	Small Industrial Service - HLF	Rate 833	$ 28,801,612		$ 28,801,612	1.99%
13	Muni. Power	Rate 841	$ 3,500,918		$ 3,500,918	0.24%
14	Int WW Pumping	Rate 842	$ 111,123		$ 111,123	0.01%
15	Railroad	Rate 844	$ 2,146,284		$ 2,146,284	0.15%
16	Street Lighting	Rate 850	$ 7,896,064		$ 7,896,064	0.54%
17	Traffic Lighting	Rate 855	$ 910,582		$ 910,582	0.06%
18	Dusk to Dawn Lighting	Rate 860	$ 2,615,562		$ 2,615,562	0.18%
19		Interdepartmental	$ 4,946,681		$ 4,946,681	0.34%
20	System Total		$ 1,482,166,742		$ 1,450,620,450	100.00%

Tracker Allocators
2018 Electric Rate Case
Demand Allocation Support

Rate 831

Line No.	Description	Billing Determinants (kWh, kW)	Proposed Rate	Revenue	Total Revenue	Tier 1 Revenue
	Billed kW					
1	Firm Contract Demand	2,334,672	$ 22.97	$ 53,617,496	$ 53,617,496	$ 53,617,496
2						
3	Total kW	2,334,672		$ 53,617,496	$ 53,617,496	
	Energy Charge					
4	Variable O&M	1,534,532,236	$ 0.003435	$ 5,270,461	$ 5,270,461	$ 5,270,461
5	Fuel	1,684,938,526	$ 0.026446	$ 44,559,646	$ 44,559,646	$ 44,559,646
6	Transmission Charge	5,031,239,483	$ 0.008573	$ 43,132,596	$ 43,132,596	$ 14,444,904
	Adjacent Qualifying Facility Premise					
7	Transmission Charge	1,222,643,106	$ 0.002572	$ 3,144,500	$ 3,144,500	$ -
8	Transmission Charge Subtotal	6,253,882,589		46,277,096		
9	Total Energy Charge			$ 96,107,204	$ 96,107,204	$ 117,892,508
10	Other Revenue					$ 2,827,783
	Discounts - Billed kW					
11	Lagging RKVA Discount	(893,436)	$ 0.32	$ (285,900)	$ (285,900)	
12	Total Discount	(893,436)		$ (285,900)	$ (285,900)	
13	Industrial Power Service - Large (Rate 831)			$ 149,438,800	$ 149,438,800	$ 149,438,800
14	Other Revenue / Rate 831 Tier 1 Adjustment				$ 2,827,783	$ 31,546,292
15	Total				$ 152,266,583	

			%
Transmission kWh		5,031,239,483	100.00%
Adjacent Qualifying Facility Premise Transmission kWh	1,222,643,106	-	0.00%
Total		5,031,239,483	

Tracker Allocators
2018 Electric Rate Case
Demand Allocation Support

Description	Rates	Demand Allocators - Total Revenue	Rate 831 Tier 1 Adjustment	Revised Revenue	Resulting % Allocation on Revenue"
Residential	Rate 811	$ 508,397,289		$ 508,397,289	35.05%
C&GS Heat Pump	Rate 820	$ 914,117		$ 914,117	0.06%
GS Small	Rate 821	$ 253,812,406		$ 253,812,406	17.50%
Comml SH	Rate 822	$ 1,211,193		$ 1,211,193	0.08%
GS Medium	Rate 823	$ 165,705,139		$ 165,705,139	11.42%
GS Large	Rate 824	$ 207,833,587		$ 207,833,587	14.33%
Metal Melting	Rate 825	$ 7,273,007		$ 7,273,007	0.50%
Off-Peak Serv.	Rate 826	$ 121,033,845		$ 121,033,845	8.34%
Industrial Power Service - Large	Rate 831				
Tier 1	Tier 1	$ 152,266,583	$ (31,546,292)	$ 120,720,291	8.32%
Small Industrial Service - LLF	Rate 832	$ 12,790,750		$ 12,790,750	0.88%
Small Industrial Service - HLF	Rate 833	$ 28,801,612		$ 28,801,612	1.99%
Muni. Power	Rate 841	$ 3,500,918		$ 3,500,918	0.24%
Int WW Pumping	Rate 842	$ 111,123		$ 111,123	0.01%
Railroad	Rate 844	$ 2,146,284		$ 2,146,284	0.15%
Street Lighting	Rate 850	$ 7,896,064		$ 7,896,064	0.54%
Traffic Lighting	Rate 855	$ 910,582		$ 910,582	0.06%
Dusk to Dawn Lighting	Rate 860	$ 2,615,562		$ 2,615,562	0.18%
	Interdepartmental	$ 4,946,681		$ 4,946,681	0.34%
System Total		$ 1,482,166,742		$ 1,450,620,450	100.00%

Tracker Allocators
2018 Electric Rate Case
Energy Allocation

Line	Description	Rate Class	MWH at the Source	% Allocation on Sales
1	Residential	Rate 811	3,574,056	28.86%
2	C&GS Heat Pump	Rate 820	10,918	0.09%
3	GS Small	Rate 821	1,692,423	13.67%
4	Comml SH	Rate 822	12,282	0.10%
5	GS Medium	Rate 823	1,324,381	10.69%
6	GS Large	Rate 824	1,925,038	15.54%
7	Metal Melting	Rate 825	97,218	0.78%
8	Off-Peak Serv.	Rate 826	1,327,574	10.72%
9	Industrial Power Service - Large	Rate 831		
	Tier 1		1,716,774	13.86%
	Tier 2		0	0.00%
10	Small Industrial Service - LLF	Rate 832	152,471	1.23%
11	Small Industrial Service - HLF	Rate 833	408,867	3.30%
12	Muni. Power	Rate 841	29,678	0.24%
13	Int WW Pumping	Rate 842	355	0.00%
14	Railroad	Rate 844	21,905	0.18%
15	Street Lighting	Rate 850	42,843	0.35%
16	Traffic Lighting	Rate 855	6,532	0.05%
17	Dusk to Dawn Lighting	Rate 860	15,291	0.12%
18		Interdepartmental	26,376	0.21%
19	System Total		12,384,981	100%

Tracker Allocators
2018 Electric Rate Case
TDSIC Allocation

Transmission and Distribution
Revenue Requirement Allocation

*For purposes of recovering approved capital TDSIC expenditures and costs pursuant to I.C. 8-1-39-9(a), the following class allocation factor percentages shall be applied to the respective distribution- or transmission-related revenue requirement and then the resulting TDSIC charge factors (per kWh) applied to each customer's firm (or non-interruptible) load within that class:

Line	Description	Rate Class	Transmission Rev. Req. Allocation Factor %	Distribution Rev. Req. Allocation Factor %
1	Residential	Rate 811	36.65%	53.48%
2	C&GS Heat Pump	Rate 820	0.11%	0.19%
3	GS Small	Rate 821	15.95%	17.65%
4	Comml SH	Rate 822	0.12%	0.18%
5	GS Medium	Rate 823	11.67%	9.90%
6	GS Large	Rate 824	13.82%	10.77%
7	Metal Melting	Rate 825	0.48%	0.53%
8	Off-Peak Serv.	Rate 826	8.49%	5.98%
9	Industrial Power Service - Large	Rate 831	8.55%	0.00%
10	Small Industrial Service - LLF	Rate 832	1.05%	0.00%
11	Small Industrial Service - HLF	Rate 833	2.26%	0.00%
12	Muni. Power	Rate 841	0.25%	0.33%
13	Int WW Pumping	Rate 842	0.00%	0.00%
14	Railroad	Rate 844	0.14%	0.00%
15	Street Lighting	Rate 850	0.07%	0.27%
16	Traffic Lighting	Rate 855	0.04%	0.03%
17	Dusk to Dawn Lighting	Rate 860	0.04%	0.20%
		Interdepartmental	0.31%	0.50%
18	System Total		100.00%	100.00%

Tracker Allocators
2018 Electric Rate Case
TDSIC Allocation Support

TDISC Allocators

Rate	Trans	Sub Trans	Total	831 Tier 1 Adj	Adj. Total	Transmission Rev. Req. Allocation Factor
Rate 811	$ 40,202,805	$ 9,738,719	$ 49,941,524		$ 49,941,524	36.65%
Rate 820	$ 106,041	$ 45,896	$ 151,937		$ 151,937	0.11%
Rate 821	$ 17,869,739	$ 3,858,926	$ 21,728,665		$ 21,728,665	15.95%
Rate 822	$ 122,851	$ 43,518	$ 166,369		$ 166,369	0.12%
Rate 823	$ 13,545,126	$ 2,362,188	$ 15,907,314		$ 15,907,314	11.67%
Rate 824	$ 16,052,377	$ 2,778,410	$ 18,830,787		$ 18,830,787	13.82%
Rate 825	$ 471,091	$ 176,362	$ 647,453		$ 647,453	0.48%
Rate 826	$ 9,953,037	$ 1,618,947	$ 11,571,984		$ 11,571,984	8.49%
Rate 831	$ 46,812,162	$ 778,690	$ 47,590,853	24.48%	$ 11,651,965	8.55%
Rate 832	$ 1,295,072	$ 141,359	$ 1,436,432		$ 1,436,432	1.05%
Rate 833	$ 2,954,176	$ 119,153	$ 3,073,328		$ 3,073,328	2.26%
Rate 841	$ 266,805	$ 73,950	$ 340,755		$ 340,755	0.25%
Rate 842	$ 2,535	$ 336	$ 2,871		$ 2,871	0.00%
Rate 844	$ 124,451	$ 62,044	$ 186,495		$ 186,495	0.14%
Rate 850	$ 38,830	$ 61,938	$ 100,767		$ 100,767	0.07%
Rate 855	$ 51,320	$ 7,114	$ 58,433		$ 58,433	0.04%
Rate 860	$ 18,423	$ 31,541	$ 49,964		$ 49,964	0.04%
Interdepartmental	$ 300,492	$ 123,169	$ 423,661		$ 423,661	0.31%
Total	$ 150,187,333	$ 22,022,260	$ 172,209,593		$ 136,270,706	100%

Tier 1 Transmission Volumes	1,534,532,236	24.48%
Total Transmission Volumes'	6,267,586,326	

Rate	Dist Primary	Dist Secondary	Total	Distribution Rev. Req. Allocation Factor
Rate 811	$ 79,507,533	$ 32,262,948	$ 111,770,481	53.48%
Rate 820	$ 374,700	$ 17,911	$ 392,612	0.19%
Rate 821	$ 31,431,404	$ 5,458,155	$ 36,889,559	17.65%
Rate 822	$ 355,284	$ 26,207	$ 381,491	0.18%
Rate 823	$ 19,272,477	$ 1,419,524	$ 20,692,002	9.90%
Rate 824	$ 21,864,911	$ 639,198	$ 22,504,109	10.77%
Rate 825	$ 1,077,024	$ 27,080	$ 1,104,104	0.53%
Rate 826	$ 12,110,993	$ 394,245	$ 12,505,238	5.98%
Rate 831	$ -	$ -	$ -	0.00%
Rate 832	$ 0	$ -		0.00%
Rate 833	$ (0)	$ -	$ (0)	0.00%
Rate 841	$ 603,733	$ 81,096	$ 684,828	0.33%
Rate 842	$ 2,744	$ 763	$ 3,507	0.00%
Rate 844	$ -	$ -	$ -	0.00%
Rate 850	$ 505,664	$ 53,048	$ 558,712	0.27%
Rate 855	$ 58,075	$ 6,859	$ 64,934	0.03%
Rate 860	$ 257,503	$ 159,191	$ 416,694	0.20%
Interdepartmental	$ 1,005,562	$ 31,466	$ 1,037,029	0.50%
Total	$ 168,427,607	$ 40,577,693	$ 209,005,300	100.00%

NORTHERN INDIANA PUBLIC SERVICE COMPANY **Original Sheet No. 201**
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Sheet No. 1 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 870	FAC	Adjustment of Charges for Cost of Fuel Rider	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 871	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 874	RA	Adjustment of Charges for Resource Adequacy	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 876	BMTIS	Back-Up and Maintenance Industrial Service Rider	831
Rider 877	EDR	Economic Development Rider	824, 826, 832, 833
Rider 878	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	811, 820, 821, 822, 823, 824, 825, 826, 832, 833, 841, 844,
Rider 879	IS	Interconnection Standards	811, 820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, 844, 865
Rider 880	NM	Net Metering	811, 820, 821, 822, 823, 824, 825, 826, 832, 833, 841

Issued Date
__/__/2019

Effective Date
6/30/2019

NIPSCO

NORTHERN INDIANA PUBLIC SERVICE COMPANY **Original Sheet No. 202**
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 881	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	823, 824, 825, 826, 831, 832, 833
Rider 882	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	823, 824, 825, 826, 831, 832, 833
Rider 883	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 844, Rider 876
Rider 886	GPR	Green Power Rider	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, and Rider 876
Rider 887	FMCA	Adjustment of Charges for Federally Mandated Costs	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 888	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876

NORTHERN INDIANA PUBLIC SERVICE COMPANY **Original Sheet No. 201~~187~~**
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Sheet No. 1 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 870	FAC	Adjustment of Charges for Cost of Fuel Rider	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 871	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 874	RA	Adjustment of Charges for Resource Adequacy	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, ~~842, 844,~~ 850, 855, 860, Rider 876
Rider 876	BMTIS	Back-Up and Maintenance Industrial Service Rider	831
Rider 877	EDR	Economic Development Rider	824, 826, ~~830~~832, 833
Rider 878	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 832, 833, 841, 844,
Rider 879	IS	Interconnection Standards	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831, 832, 833, 841, 844, 865
Rider 880	NM	Net Metering	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 832, 833, 841

Issued Date
__/__/2019

Effective Date
6/30/2019

NIPSCO®

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

Original Sheet No. 202~~188~~

APPENDIX A
APPLICABLE RIDERS

Sheet No. 2 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 881	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	823, 824, 825, 826, ~~830,~~ 831, 832, 833
Rider 882	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	823, 824, 825, 826, ~~830,~~ 831, 832, 833
Rider 883	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~831 Tier 1, 832, 833, 841, 844, Rider 876
Rider 886	GPR	Green Power Rider	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, and Rider 876
Rider 887	FMCA	Adjustment of Charges for Federally Mandated Costs	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 888	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876

Issued Date
__/__/2019

Effective Date
6/30/2019

NIPSCO

Rate 831 Implementation Agreement Confidential Exhibit C (Redacted)
Cause No. 45159

1. Tier 2 and/or Tier 3 Contract Terms.

The Rate 831 Settling Parties agree that any contract for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions:

(a) identify NIPSCO as the Market Participant for the retail customer at Midcontinent Independent System Operator, Inc. ("MISO");

(b) reference NIPSCO's market-based rate authority with Federal Energy Regulatory Commission ("FERC");

(c) clearly state the Rate 831 customer remains a retail customer of NIPSCO;

(d) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations);

(e) incorporate relevant provisions of the Rate 831 tariff;

(f) all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and

(g) any information shared with NIPSCO shall be subject to a confidentiality agreement applicable to all other terms of said agreements.

2. Rate Implementation Dates.

The Rate 831 Settling Parties agree that the customer's elections under Rate 831 Tiers 2 and/or Tier 3 shall occur in a window between the day after NIPSCO's compliance filing in this Cause to thirty (30) days thereafter. Customer recognizes that in

order to implement Tier 3, customer may need to install software including a security certificate to be provided by NIPSCO. The parties agree to work together during the 30 day period to achieve implementation.

3. Firm Capacity Transactions.

NIPSCO agrees that under either Tier 2 or Tier 3, a customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges.

4. Dispute Resolution.

NIPSCO agrees that the third party energy and capacity supplier may represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the Indiana Utility Regulatory Commission. At a minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.

Exhibit 104

Counsel for Public Interest Organizations stated that this document was published in full, including the material labelled "Confidential" beginning on page 110, on August 2, 2023, on the website of the Indiana Utility Regulatory Commission.

The previously published document can be found here:

https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/a4adc395-4031-ee11-bdf4-001dd80abde3/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_45772_080223.pdf

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 104
NIPSCO 2023 Rate Order

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61, AND, 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF A NEW RIDER FOR VARIABLE NON-LABOR O&M EXPENSES ASSOCIATED WITH COAL-FIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POST-RETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.

CAUSE NO. 45772

APPROVED: AUG 02 2023

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
David E. Ziegner, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

Table of Contents

Page

1. Notice and Jurisdiction. 5

2. Petitioner's Organization and Business. 5

3. Existing Rates. 6

4. Test Year and Rate Base Cutoff. 6

5. NIPSCO's Requested Relief. 7

6. Opposition, Rebuttal, and Cross-Answering. 8

7. Settlement Agreement. 8
- A. Overview. 9
- B. Revenue Requirement. 10
- C. Original Cost Rate Base, Capital Structure and Rate of Return. 11
- D. Depreciation Rates and Amortization. 12
- E. Pro Forma Net Operating Income at Present Rates. 16
- F. Environmental Cost Tracker. 17
- G. Phased Rate Implementation. 18
- H. Cost of Service, Rate Design, and Rate 831/531 Modification Settlement. ..19
- I. Low Income Program. 24
- J. Other Relief Requested by NIPSCO. 24
- K. Typical Bill Comparison. 24
- L. Addenda to the Settlement Agreement. 25
- M. Public Interest. 26

8. Opposition to Settlement Agreement. 27

9. Settlement Rebuttal. 28

10. Commission Discussion and Findings. 32
- A. Disputed Issues. 34
- B. Ultimate Findings on Settlement Agreement and Rate 831/531 Modification Settlement. 39

11. Effect of Settlement Agreement. 43

12. Confidentiality. 43

On September 19, 2022, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below.[1] Also on September 19, 2022, Petitioner filed its case-in-chief, workpapers, and information required by the minimum standard filing requirements set forth at 170 IAC 1-5. NIPSCO's case-in-chief included testimony, attachments, and workpapers from the following witnesses:[2]

- Michael Hooper, President and Chief Operating Officer, NIPSCO;
- Erin E. Whitehead, Vice President of Regulatory Policy and Major Accounts, NIPSCO;
- Jennifer L. Shikany, Director of Regulatory Utilities and Optimization, NiSource Corporate Services Company ("NCSC");
- Kevin J. Blissmer, Manager of Regulatory, NCSC;
- Angela Camp, Director of Regulatory and Utility Planning, NCSC;
- Nick Bly, Manager of Corporate Consolidation in Financial Planning & Analysis, NCSC;
- Gunnar J. Gode, Vice President and Chief Accounting Officer, NCSC;
- Patrick L. Baryenbruch, President, Baryenbruch & Company, LLC;
- Ronald E. Talbot, Senior Vice President of Electric Operations, NIPSCO;
- Kelly R. Carmichael, Vice President, Environmental Policy, NCSC;
- Andrew S. Campbell, Director of Portfolio Planning & Origination, NIPSCO;
- Patrick N. Augustine, Vice President in Charles River Associates' Energy Practice;
- Kimberly Cartella, Director of Compensation, NCSC;
- Jeffrey T. Kopp, Senior Managing Director, 1898 & Co.;
- John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC;
- Vincent V. Rea, Managing Director of Regulatory Finance Associates, LLC;
- Jennifer A. Harding, Director of Income Tax Operations for NCSC;
- Melissa Bartos, Vice President, Concentric Energy Advisors;
- John D. Taylor, Managing Partner with Atrium Economics, LLC;
- Judith L. Siegler, Lead Operations Analyst, NCSC; and
- Alison M. Becker, Manager of Regulatory Policy, NIPSCO.

As part of its requested relief, NIPSCO sought approval of an Alternative Regulatory Plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 which would continue, with certain modifications, the existing Rate 831 industrial service structure. Petitioner further asked that the Commission approve the Stipulation and Settlement Agreement on Rate 831/531 Modification ("Rate 831/531 Modification Settlement") between itself and seven current Rate 831 customers.

Petitioner also filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on September 19, 2022, which was granted by Commission Docket Entry

---

[1] On August 15, 2022, NIPSCO provided its notice of intent to file a rate case in accordance with the Commission's General Administrative Order 2013-5. Pet. Ex. 1, Attachment 1-B.

[2] NIPSCO filed additional information on September 20, 2022 and November 15, 2022. NIPSCO filed corrections to its case-in-chief on January 31, 2023 and April 21, 2023. NIPSCO also late-filed Attachments 1-C and 1-D (consisting of the Proofs of Legal Notice Publication and Customer Notice) of Petitioner's Exhibit 1.

dated October 7, 2022. Petitioner submitted the Confidential Information preliminarily granted confidential treatment pursuant to the instructions in such docket entry.

Petitions to Intervene were filed by the United States Steel Corporation ("U.S. Steel"); NLMK Indiana, a division of NLMK USA ("NLMK"); ChargePoint, Inc.; NIPSCO Industrial Group ("Industrial Group");[3] Walmart Inc. ("Walmart"); Citizens Action Coalition of Indiana, Inc. ("CAC"); Indiana Municipal Utility Group ("IMUG");[4] RV Industry User's Group ("RV Group");[5] Midwest Industrial User's Group ("MIUG");[6] and City of Michigan City, Indiana ("Michigan City"). These petitions were granted without objection. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated as a party.

On October 7, 2022, a Docket Entry was issued establishing a procedural schedule and related requirements and approving certain stipulations the parties filed on September 19, 2022.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held in Hammond, Indiana on December 12, 2022 and in Valparaiso, Indiana on January 4, 2023, at which time members of the public presented testimony.

On January 20, 2023, the OUCC and certain intervenors filed their respective cases-in-chief. For purposes of its case-in-chief, the OUCC prefiled written consumer comments in Public's Exhibit 13 and testimony and attachments from the following witnesses:

- Michael D. Eckert, Director, OUCC Electric Division;
- Mark E. Garrett, President of Garrett Group Consulting, Inc.;
- Wes R. Blakley, Senior Utility Analyst, OUCC Electric Division;
- Cynthia M. Armstrong, Chief Technical Advisor, OUCC Electric Division;
- David J. Garrett, Managing Member of Resolve Utility Consulting, PLLC;[7]
- April M. Paronish, Assistant Director, OUCC Electric Division;
- John E. Haselden, Consultant;
- Brian Latham, Utility Analyst, OUCC Electric Division;
- Kaleb G. Lantrip, Utility Analyst, OUCC Electric Division;
- Peter M. Boerger, PhD, President of Economics Workshop, LLC;[8] and
- Glenn A. Watkins, President and Senior Economist of Technical Associates, Inc.

[3] The companies that comprise the Industrial Group are Accurate Castings and Kingsbury Castings, BP Products North America, Inc., Cargill, Inc., Cleveland-Cliffs Steel LLC, Enbridge, Linde, Marathon, and USG Corporation.

[4] The municipalities that comprise IMUG are Town of Schererville, Town of Dyer, and City of East Chicago.

[5] The companies that comprise the RV Group are: LCI Industries, Inc., Forest River, Inc., Patrick Industries, Inc., and Keystone RV Company.

[6] The companies that comprise the MIUG are Ball Metal Beverage Container Corporation; Material Sciences Corporation; and Albanese Confectionery Group, Inc.

[7] Pub. Ex. 5 (Depreciation) and Pub. Ex. 12 (Return on Equity).

[8] On February 16, 2023, the OUCC prefiled corrections to Mr. Boerger's testimony.

The Industrial Group prefiled testimony and attachments from James R. Dauphinais and Michael P. Gorman, both Consultants and Managing Principals with Brubaker & Associates, Inc., and Brian C. Andrews, an Associate with Brubaker & Associates, Inc.

Walmart prefiled the testimony and attachments of Alex J. Kronauer, Senior Manager, Energy Services for Walmart.

CAC prefiled the testimony and attachments of Benjamin Inskeep, CAC Program Director, Ron Nelson, Senior Director at Strategen Consulting, and Scott Reeves, Director on the Distributed Energy Resources and Electrification team at the Cadeo Group.

RV Group prefiled the testimony and attachments of Jeffry Pollock, Energy Advisor and President of J. Pollock, Incorporated and Jonathan W. Burke, President and CEO of Tactical Energy Group.

MIUG prefiled the testimony and attachments of Michael R. O'Connell, Vice President of Industrial Solutions at Midwest Wholesale Power Specialists LLC.[9]

U.S. Steel prefiled the testimony of Ralph R. Riberich, Jr., Director of Procurement for U.S. Steel.

IMUG prefiled the testimony of Ted Sommer, Partner with the Firm of London Witte Group, LLC.

On February 16, 2023, the OUCC prefiled cross-answering testimony of Michael D. Eckert and Peter M. Boerger, PhD; the Industrial Group prefiled cross-answering testimony of Brian C. Andrews and James R. Dauphinais; CAC prefiled cross-answering testimony of Ron Nelson and Benjamin Inskeep; RV Group prefiled cross-answering testimony of Jeffry Pollock; U.S. Steel prefiled cross-answering testimony of Tony M. Georgis, Managing Partner of the Energy Practice at NewGen Strategies and Solutions, LLC; NLMK prefiled cross-answering testimony of Frank W. Radigan, Principal, Hudson River Energy Group; and Michigan City prefiled cross-answering testimony of Mayor Duane Parry.

Also on February 16, 2023, NIPSCO prefiled rebuttal testimony, exhibits, and workpapers for the following witnesses:

- Erin E. Whitehead;
- Jennifer L. Shikany;
- Kevin J. Blissmer;
- Patrick L. Baryenbruch;
- Ronald E. Talbot;
- Kelly R. Carmichael;
- Andrew S. Campbell;

[9] On February 3, 2023, MIUG substituted Mr. O'Connell for Matthew D. Alvarez. On February 16, 2023, NIPSCO filed a motion to strike two questions and answers in their entirety. By Docket Entry dated March 3, 2023, the Presiding Officers partially granted NIPSCO's Motion. The version of testimony admitted into the record did not include the struck language.

- Patrick N. Augustine;
- Kimberly Cartella;
- John J. Spanos;
- Vincent V. Rea;
- Melissa Bartos;
- John D. Taylor;
- Alison M. Becker; and
- Alan Felsenthal, Managing Director, PricewaterhouseCoopers LLP.

On March 6, 2023, NIPSCO, the OUCC, Industrial Group, NLMK, and Walmart filed a Notice of Agreement in Principle with Less Than All the Parties, Request to Vacate Evidentiary Hearing Dates, and Motion for Approval of Agreed Procedure Schedule ("Joint Motion"). In the Joint Motion, the parties advised an agreement in principle on all issues in this Cause had been reached.[10] The Joint Motion also included an agreed procedural schedule for settlement in this Cause.

By Docket Entry dated March 7, 2023, the Presiding Officers revised the procedural schedule to accommodate presentation of the settlement and supporting evidence, as well as to establish a post-hearing schedule.

On March 10, 2023, a Stipulation and Settlement Agreement ("Settlement" or "Settlement Agreement") was filed by NIPSCO, the OUCC, Industrial Group, NLMK, U.S. Steel,[11] Walmart, and RV Group (collectively the "Settling Parties").

On March 17, 2023, NIPSCO prefiled the settlement testimony, attachments, and workpapers of Ms. Whitehead, Ms. Shikany, and Mr. Taylor in support of the Settlement Agreement. Also on March 17, 2023, the other Settling Parties filed additional evidence supporting the Settlement Agreement from the following witnesses:

- Michael D. Eckert;
- Peter M. Boerger;
- Michael P. Gorman;
- James R. Dauphinais;
- Ted Sommer;
- Ralph R. Riberich, Jr.;
- Alex J. Kronauer;
- Jonathan W. Burke; and
- Frank W. Radigan.

[10] The Joint Motion indicated NIPSCO was in continuing discussions with all other parties to the proceeding and anticipated some of them would also sign, or not oppose, the settlement. Joint Motion, fn2.

[11] U.S. Steel made a motion to late file its signature page on March 13, 2023, which was granted by Docket Entry on March 24, 2023.

On March 31, 2023, MIUG and Michigan City filed additional testimony of Michael R. O'Connell and Duane Parry, respectively, opposing the Settlement Agreement. Also on March 31, 2023, CAC and ChargePoint filed notices of non-opposition to the Settlement.

On April 10, 2023, NIPSCO prefiled the settlement reply testimony of Ms. Whitehead, Mr. Campbell, and Mr. Taylor and the Industrial Group prefiled settlement reply evidence of James R. Dauphinais.

Also on April 10, 2023, NIPSCO, the Industrial Group, and NLMK jointly filed an objection and motion to strike MIUG Witness O'Connell's opposition testimonies. On April 20, 2023, MIUG filed its response, along with alternative revised testimonies of Mr. O'Connell. On April 24, 2023, the moving parties withdrew their objection to Mr. O'Connell's revised Rates 526/532/533 testimony and proposed that with the removal of three additional questions and answers, specifically questions and answers 30, 31, and 32, from Mr. O'Connell's Rate 531 testimony, joint movants would withdraw their objection to the remainder of Mr. O'Connell's revised Rate 531 testimony.[12] MIUG agreed to joint movants' proposal prior to the hearing. At the hearing, the version of testimonies admitted into the record for Mr. O'Connell reflected the agreement and joint movants withdrew their objection and motion to strike.

A public evidentiary hearing was conducted in this Cause starting at 9:00 a.m. on April 26, 2023, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the evidentiary hearing, the Settlement Agreement and all of the direct, cross-answering, rebuttal, and settlement, opposing settlement, and settlement reply testimony and exhibits of each party were offered and admitted into the record.

The Commission, based upon applicable law and the evidence, finds as follows:

1. Notice and Jurisdiction. Legal and timely notice of the public hearings held in this Cause was given and published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a) and an "energy utility" as that term is defined in Ind. Code § 8-1-2.5-2. NIPSCO has also elected to become subject to Ind. Code § 8-1-2.5-6. NIPSCO caused to be published the filing of its petition pursuant to Ind. Code §§ 8-1-2-61 and 8-1-2.5-6 and mailed notice to its customers pursuant to 170 IAC 4-1-18(C). The Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. Petitioner's Organization and Business. NIPSCO is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders retail electric utility service to more than 483,000 retail customers located in all or part of the following Indiana counties: Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren, and White. Additionally, NIPSCO is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and is a member of Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization ("RTO") operated under FERC's

[12] As part of the agreement with MIUG to further revise Mr. O'Connell's prefiled Rate 531 testimony by removing questions and answers 30, 31, and 32, the Industrial Group, as a joint movant, agreed not to offer Mr. Dauphinais' pre-filed settlement reply testimony into evidence at the evidentiary hearing.

authority that controls the use of NIPSCO's transmission system and the dispatching of NIPSCO's generating units.

NIPSCO owns, operates, manages, and controls electric generating, transmission and distribution plant and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, distribution and furnishing of electric energy, heat, light, and power to the public. NIPSCO classifies its property in accordance with the Uniform System of Accounts as prescribed by FERC and approved and adopted by the Commission.

3. Existing Rates. The Commission approved NIPSCO's current electric basis rates and charges in its December 4, 2019 Order in Cause No. 45159 ("45159 Order"). The petition initiating Cause No. 45159 was filed with the Commission on October 31, 2018; therefore, in accordance with Ind. Code § 8-1-2-42(a), it has been more than 15 months since NIPSCO filed its most recent petition for an increase in basic rates and charges and the filing of NIPSCO's Petition in this Cause.

In the 45159 Order, the Commission approved an ARP for NIPSCO's large industrial service structure, which is embodied in NIPSCO's existing Rate 831. Rate 831 has three tiers of service. All customers on Rate 831 must sign a contract which expires the earlier of five years or the approval of rates in NIPSCO's ensuing general rate case. Each Rate 831 customer must take a minimum of 10 megawatts ("MW") of Tier 1 firm service. By default, Tier 2 service is non-firm curtailable service, and NIPSCO will register as load modifying resource ("LMR") at MISO that portion of a customer's Tier 2 contract demand for which capacity is not procured through MISO's planning reserve auction ("PRA") or contracted through a third party. Under Tier 2, the customer will take all energy at the MISO Day-Ahead Locational Marginal Price at the applicable company Load Zone. Tier 3 is also, by default, non-firm curtailable service, and NIPSCO will register as a LMR at MISO that portion of a customer's Tier 3 contract demand for which capacity is not procured through MISO's PRA or contracted through a third party. Under the Tariff, NIPSCO will only register a single LMR for any non-firm load if a customer chooses to take both Tier 2 and 3 service. NIPSCO, as the MISO Market Participant, will register participating customers as an Asset Owner at MISO, which will allow the customer access to the MISO Market Portal to carry out MISO Asset Owner functions. 45159 Order, pp. 40-41. The Commission approved the ARP and a Rate 831 Settlement and Implementation Agreement among fewer than all parties. *Id.* at pp. 151-157, 170. Under the Rate 831 Settlement and Implementation Agreement, rates were designed based upon an assumed subscribed Tier 1 contractual demand of 194.556 MW. There are seven large industrial customers who have executed contracts and are currently taking service pursuant to Rate 831.

4. Test Year and Rate Base Cutoff. As authorized by Ind. Code § 8-1-2-42.7(d)(1), Petitioner proposed a forward-looking test period using projected data, with the test year used for determining Petitioner's projected operating revenues, expenses, and net operating income being the 12-month period ending December 31, 2023. NIPSCO is utilizing the test year end, December 31, 2023, as the general rate base cutoff date. The historical base period is the 12-month period ending December 31, 2021.

5. NIPSCO's Requested Relief. NIPSCO seeks a general increase in rates and charges and approval of new schedules of rates and charges, including modifications of language in its tariff. By its Petition, NIPSCO requested approval of a new variable cost tracker ("VCT") that would move approximately $102 Million out of its current base rates and into the new VCT. Including both the projected revenues from the new VCT and the requested rate increase from base rates, NIPSCO requested Commission approval of an overall annual increase in revenues of approximately $395 Million, or approximately 25.85%. NIPSCO proposed to implement the requested base rate revenue increase in two steps on a phased-in basis. Step 1 would be upon issuance of the Commission's Order and based upon actual rate base and capital structure as of June 30, 2023, and Step 2 would be based upon actual rate base and capital structure as of the end of the test year. What is effectively a third step would take effect upon approval of the VCT. NIPSCO's proposed rates would capture within rate base the cost of NIPSCO's investment in several renewable joint venture projects that were approved in Cause Nos. 45194, 45310, 45524, and 45462, specifically Rosewater Wind, Crossroads Wind, Crossroads Solar, and Dunn's Bridge I Solar, respectively. NIPSCO also sought:

- approval of new common and electric depreciation accrual rates and amortization periods for regulatory assets;
- authority to remove Off System Sales margins from its RTO tracker and instead to pass back 100% of Off System Sales revenues net of expenses through the fuel adjustment clause ("FAC");
- authority to modify joint venture accounting authority so as to combine reserve accounts for purposes of passing joint venture cash back to customers;
- approval of a new station power rate for renewable wholesale generation facilities;
- approval of a new electric vehicle fast charging rate for use at NIPSCO-owned public electric charging stations;
- authority to file a docketed proceeding outside of a general rate case seeking authority to implement a tax rate modification mechanism, in the event of a change in state or federal income tax rates;
- review of the FAC earnings bank;[13]
- approval of a new ARP to implement a proposed low income program; and
- various accounting authorities, including approval of regulatory accounting authority for pension and other post-retirement benefits ("OPEB"), for cost of removal at coal-fired generation assets following the retirement of Michigan City Unit 12, for discounts provided pursuant to the Economic Development Rider, and costs to be recovered through the proposed VCT until such costs are recovered through the VCT.

Prior to filing its Petition, NIPSCO negotiated with its seven large industrial customers taking service under Rate 831. Each of these customers is currently taking service pursuant to a contract that would have expired by its terms upon approval of new rates in this case. Under the provisions of the Rate 831 tariff, upon the expiration of the current contracts, each of those customers could elect to execute a new contract reducing their Tier 1 firm contract demand to as low as the tariff minimum of 10 MW. Had each elected to do so, the Rate 831 demand for cost of

[13] NIPSCO sought essentially this same review in Cause No. 38706 FAC 136. The Commission has already determined the issue raised by NIPSCO, thus rendering moot this aspect of Petitioner's request.

service and revenue allocation purposes would decrease from the current level of 194.556 MW to 70 MW. NIPSCO presented as part of its case-in-chief the Rate 831/531 Modification Settlement to resolve this risk. Pet. Ex. 2, Att. 2-B.

The Rate 831/531 Modification Settlement provides that 180 MW of production-related demand costs would be allocated to Rate 531 in this rate case based upon the 4 coincident peak ("CP") method, and further provides for transmission demand to be allocated based upon the 12 CP method. These allocation methods are consistent with how production- and transmission-related demand was allocated in Cause No. 45159. Rates for Rate 531, however, would be designed using the seven customers' combined, committed, Tier 1 firm demand of 170 MW, thereby retaining most of the firm load currently served under Rate 831. The current Rate 831 customers agreed to enter into new contracts that would be effective until the earlier of the effective date for new rates under NIPSCO's next electric rate case filing after this case or May 31, 2026. The Rate 831/531 Modification Settlement reserves the right of the customers to reduce their demand at the expiration of these contracts consistent with the terms of NIPSCO's tariff. Further, recognizing that the 180 MW of production-related demand allocated to the Rate 531 customers will exceed the actual contractual Tier 1 demand subscriptions, the 831/531 Modification Settlement provides that in future rate proceedings the cost allocation to Rate 831 (and any successor rate) will continue to move the class toward the actual cost of service based on actual contract demands.

In all other respects, except minor modifications, the Rate 831/531 Modification Settlement preserves the existing Rate 831 terms and conditions of service approved as an ARP in Cause No. 45159, including, but not limited to: the designation of only Tier 1 load as "firm load for transmission, distribution, and storage system improvement charge ("TDSIC") revenue allocation purposes"; the methodology to establish tracker allocations; and the continuation of terms related to the "Adjacent Affiliate Qualified Facility Premise Transmission Charge."

6. <u>Opposition, Rebuttal, and Cross-Answering</u>. The OUCC and intervenors raised numerous challenges to NIPSCO's filing, including challenging rate base, rate of return, operation and maintenance ("O&M") expenses, depreciation rates, rider proposals, cost of service allocation, and rate design. The extent to which these parties disagreed with each other is shown in their cross-answering testimony. The extent to which NIPSCO disagreed or agreed with the OUCC and intervenors was addressed in NIPSCO's rebuttal evidence.

7. <u>Settlement Agreement</u>. The Settling Parties' witnesses presented testimony in support of the Settlement Agreement. They discussed the terms of the Settlement Agreement and explained how the Settlement Agreement resolves all issues presented in the case in a fair and reasonable manner. This includes issues related to the revenue requirement, rate design, approval of the 831/531 Modification Settlement, and the establishment of an Environmental Cost Tracker ("ECT") as a revised replacement for the proposed VCT. The terms of the Settlement Agreement specifically state that it is a settlement of all the issues among all the Settling Parties in this Cause. In addition to the Settling Parties, CAC, ChargePoint, and IMUG agreed not to oppose the Settlement.

According to Mr. Eckert, if approved, the Settlement Agreement will provide certainty regarding critical issues, including revenue requirements, authorized return, and the allocation of NIPSCO's revenue requirement among its various rate classes. Pub. Ex. 16 at 2. Mr. Gorman

testified that despite the number of complex issues in the case and the parties' sometimes divergent views on those issues, they were able to reach resolution of the case, as well as two other pending matters that impacted NIPSCO's rates, through the negotiation process. IG Ex. 6 at 6.

The Settling Parties' witnesses conveyed that the Settlement Agreement is a product of a diligent effort by all Settling Parties to reach a comprehensive result. The Settling Parties agreed that the complexity of the issues and the diversity of the Settling Parties dictated the need for compromise on the part of each party involved, and the Settlement Agreement, taken as a total package, reflects a delicate balance that accommodates the interests of all Settling Parties in a reasonable manner. Pet. Ex. 2-S at 17; Pub. Ex. 16 at 2; IG Ex. 6 at 6; NLMK Ex. 2 at 1-2, 5; RV Group Ex. 4-S at 3-4; U.S. Steel Ex. 3 at 5; Walmart Ex. 2 at 6-7.

OUCC Witness Eckert testified the nature of compromise includes assessing the litigation risk that exists in a contested proceeding. He said that while the Settlement Agreement represents a balance of all interests, given the number of benefits provided to ratepayers as outlined in the Settlement Agreement, the OUCC, as the statutory representative of all ratepayers, believes the Settlement Agreement is a fair resolution, supported by evidence, and should be approved. Pub. Ex. 16 at 2. Industrial Group Witness Dauphinais added, this rate case raised a broad array of complex issues on a spectrum of subjects, with numerous parties asserting a panoply of views, yet the Settling Parties were able to find consensus on the terms of a comprehensive Settlement Agreement resolving the entirety of the case. Particularly with respect to the issues concerning cost of service, Rate 531, subsidy mitigation, Rate 532, and the new ECT, Mr. Dauphinais stated the Settlement Agreement provides a reasonable resolution that balances the interests of the diverse parties consistent with sound ratemaking policies and principles. IG Ex. 7 at 9. U.S. Steel Witness Riberich testified that approval of the Settlement Agreement as it is written is consistent with the public interest because the Settlement Agreement represents a comprehensive resolution of all the issues in this proceeding by the Settling Parties. He said the Settling Parties' evidence reflects their agreement that the Settlement resolves all disputed issues surrounding NIPSCO's revenue requirement, cost of service, and rate design and provides NIPSCO with an opportunity to earn sufficient revenues to provide reasonably adequate service and a fair return on its investment. Per Mr. Riberich, the Settlement Agreement also balances the interests of the utility's current and future customers in receiving reasonable service at a fair cost. U.S. Steel Ex. 2 at 5.

A. <u>Overview</u>. NIPSCO Witness Whitehead explained that the specific objectives addressed in the Settlement Agreement included: (1) resolution of the revenue requirements issues; (2) resolution of issues related to customer charges; (3) resolution of issues relating to Proposed Rate 531 and all other revenue allocation issues (including proposals related to Rates 526 and 550); (4) proposed implementation of an ECT; and (5) resolution of issues relating to NIPSCO's proposed low income program. Pet. Ex. 2-S at 2-3.

Ms. Whitehead noted that the Settling Parties agree that NIPSCO's base rates will be designed to produce the gross revenue amount of $1,767,260,404 prior to application of surviving Riders, plus amounts NIPSCO will recover through the new ECT, which relates to NOx emissions allowances and variable chemical costs at NIPSCO's coal-fired generating stations. These ECT costs are forecasted to be approximately $30 Million per year. Pet. Ex. 2-S at 3-4. Industrial Group Witness Dauphinais testified that the remaining $72 Million that NIPSCO originally proposed to include in its new tracker would remain embedded in base rates, and allocated between classes on

the same basis as those costs were allocated in Cause No. 45159. IG Ex. 7 at 9. Ms. Whitehead explained that under the Settlement Agreement, the total increase in base rates plus the forecasted ECT results in a revenue increase from current base rates of approximately $291.8 Million. This results in a reduction of approximately $103.2 Million from the amount NIPSCO originally requested in its case-in-chief. Pet. Ex. 2-S at 4.

On cross-examination, Industrial Group Witness Gorman was asked to compare this Settlement Agreement reduction to his originally proposed revenue requirement reduction. He originally proposed a reduction in NIPSCO's proposed revenue requirement of $164 Million, but that included Mr. Gorman's proposal to switch to a levelized return on coal generation regulatory assets rather than the declining balance plus revenue credit that was approved in the 45159 Order. Without this differential treatment, Mr. Gorman testified that the $103 Million reduction was within approximately $40 Million of his case-in-chief recommendation. Tr. at C-37 to -38.

Mr. Eckert explained that the Settlement Agreement addresses the issue of affordability, noting the Settlement Agreement reduces NIPSCO's requested revenue increase in several ways. As an example, he noted NIPSCO's rate base request is reduced by $23,700,000 (for Step 1) and $23,693,692 (net of amortization for Step 2), and the annual amortization expense in the amount of $798,660. He further explained that the Settlement Agreement removes: (1) $25 Million in fuel costs; (2) $5.8 Million in vegetation management expense; (3) $26.6 Million related to the amortization period for retired coal-fired generating units; (4) $8.8 Million related to the amortization period for retired coal-fired generating Units 14 and 15; and (5) other costs identified in his testimony and the Settlement Agreement. He said that the Settling Parties agreed to an annualized combined basic rate and rider revenue requirement increase of $291,804,809, which is a $103,205,168 or a 26.12% reduction from NIPSCO's as-filed request increase of $395,009,258. Pub. Ex. 16 at 2-3. As shown in Joint Exhibit 1, Settlement Agreement Attachment 1, the average residential electric customer using 668 kilowatt hours ("kWh") per month, paying approximately $120 in September 2022 when the case was filed, will see an overall increase of approximately $12.37 per month, or 10.3%, spread over multiple months. By comparison, NIPSCO's initial case-in-chief included a requested monthly increase of approximately $19.69, or 16.5%.

NIPSCO Witness Whitehead supported the Settlement Agreement's stipulated return on equity ("ROE") of 9.80% and NIPSCO Witness Shikany presented all the settlement adjustments in her settlement testimony. Pet. Ex. 2-S at 4 and Pet. Ex. 3-S at 8-22.

B. <u>Revenue Requirement</u>. The Settlement Agreement provides that NIPSCO will withdraw its proposed VCT and instead establish a new ECT. The ECT will recover fewer categories of costs than the proposed VCT, and the forecasted annual costs to be recovered through the ECT are $29,880,196, comprised of variable chemical expenses and NOx emissions allowances. The remaining costs NIPSCO initially proposed to recover through the VCT will be excluded from the ECT and will instead continue to be recovered through base rates allocated on the same basis as those costs were allocated in NIPSCO's last base rate case, Cause No. 45159.

The Settlement Agreement provides that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount

originally requested by NIPSCO in its case-in-chief. The agreed-upon revenue requirement reflects the depreciation study and accrual rates and amortization provided in the Settlement Agreement. The stipulated revenue requirement is calculated to produce an authorized net operating income ("NOI") of $402,900,940. NIPSCO Witness Shikany described the Step 2 revenue requirement and sponsored the supporting schedules. Pet. Ex. 3-S.

C. Original Cost Rate Base, Capital Structure and Rate of Return. The Settlement provides that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settlement provides that NIPSCO should be authorized a fair rate of return of 6.80%. The Settlement provides for a projected net original cost rate base at Step 2 of $5,925,013,822, inclusive of materials, supplies, production fuel, and regulatory assets. This amount reflects that forecasted additions to Renewable Energy Joint Venture Investments will be reduced to reflect the additional Investment Tax Credit NIPSCO will receive for Dunn's Bridge I, as reflected in NIPSCO's rebuttal alternative revenue requirement filed position. NIPSCO's current estimate is that there will be a reduction in additions to forecasted Joint Venture Regulatory Assets of $23,700,000 (for Step 1) and $23,693,692 (net of amortization for Step 2), and the annual amortization expense in the amount of $798,660. However, the Settlement Agreement provides that actual reductions will be based on final project cost, which could be slightly more or less.

The Settlement also provides for NIPSCO's forecasted capital structure, including its Prepaid Pension Asset and Post-Retirement Liability at zero cost as reflected in NIPSCO's direct and rebuttal testimony, and a stipulated return on equity of 9.80%. The Settlement provides for the following forecasted capital structure at Step 2:

	Dollars	Cost %	Weighted Average Cost of Capital %
Common Equity	$4,564,821,051	9.80%	5.06%
Long-Term Debt	$3,233,952,976	4.66%	1.70%
Customer Deposits	$59,541,950	5.63%	0.04%
Deferred Income Taxes	$1,393,665,855	0.00%	0.00%
Post-Retirement Liability	$13,945,116	0.00%	0.00%
Prepaid Pension Asset	$(424,946,780)	0.00%	0.00%
Post-1970 ITC	$640,278	7.67%	0.00%
Totals	**$8,841,620,445**		**6.80%**

In its case-in-chief, NIPSCO had proposed a 10.4% ROE and several intervenors, including the OUCC and Industrial Group, advocated for a considerably lower ROE. The testimony in support of the Settlement Agreement explained that as a result of the negotiations, a compromise was reached, resulting in a 9.80% ROE. The Settlement Agreement ROE is within the range of ROE originally recommended for NIPSCO by Mr. Gorman (i.e., 9.00% to 9.90%). Mr. Gorman testified that 9.80% was reasonable for NIPSCO given the balance of the compromises reflected in the Settlement Agreement. IG Ex. 1 at 3. NIPSCO Witness Whitehead explained that if NIPSCO's ROE is set too low, it could lead to financial insecurity that would place increased risk on NIPSCO's ability to attract capital, which could also challenge NIPSCO's ability to obtain the

capital necessary to continue to provide safe, reliable, and affordable service to its electric customers. Pet. Ex. 2-S at 4. Mr. Eckert testified that the OUCC found the agreed ROE reasonable and in the interest of ratepayers. Further, the ROE component of the weighted average cost of capital used in each of NIPSCO's capital riders will be 9.80%. Pub. Ex. At 5.

Ms. Whitehead explained that settlement agreements are not precedential and noted that an ROE of 9.80% is five basis points lower than NIPSCO's recently settled gas base rate case in Cause No. 45621 and ten basis points lower than what was agreed to in the Stipulation and Settlement Agreement on Less Than all the Issues in NIPSCO's last electric base rate case ("Revenue Settlement"). She said for all these reasons, the Settlement Agreement represents a reasonable outcome related to ROE in this proceeding. She further noted that the Settlement Agreement provides at Section C.4. that it "has accounted for the overall level of risk presented to NIPSCO by the Settlement Agreement." She explained this evidence shows that the concerns of the RV Group have been factored into the stipulated ROE. Pet. Ex. 2-S at 5-6.

OUCC Witness Eckert testified that a lower ROE benefits ratepayers by reducing the return on rate base reflected in customers' rates. He added that from the OUCC's perspective, using a 9.80% ROE for determining NIPSCO's revenue requirement in its base rates and in NIPSCO's ongoing capital riders more accurately reflects NIPSCO's risk profile than the proposed 10.40% ROE. Additionally, Mr. Eckert testified, the lower ROE reduces the return on capital investment that consumers must pay through capital riders between rate cases. Thus, he said, the Settlement Agreement establishes a balanced plan that is in the interest of ratepayers while still preserving the financial integrity of NIPSCO. Pub. Ex. 16 at 5-6. Mr. Kronauer testified that while the 9.80% ROE set forth in the Settlement Agreement is not as low as Walmart would have advocated for in litigation, Walmart believes that for purposes of settlement a 9.80% ROE provides NIPSCO the opportunity to earn a fair return while still protecting customers' expectations of safe and reliable service at just and reasonable rates. Walmart Ex. 2 at 2-3.

D. <u>Depreciation Rates and Amortization</u>. In its case-in-chief, NIPSCO presented the testimony and the depreciation study of John R. Spanos, who calculated new common and electric depreciation accrual rates based upon the average service life ("ALG") method, as opposed to the equal life group ("ELG") method that had been previously approved for NIPSCO. This change from ELG produced a reduction in depreciation expense from what it would have been of $45,670,313. Pet. Ex. 15 at 23. OUCC Witness D. Garrett proposed several service life changes, recommended mitigation to growth in negative net salvage percentages, and proposed other changes. OUCC Witness Armstrong proposed to include in the costs of decommissioning the costs of coal combustion residual ("CCR") remediation at NIPSCO's Michigan City and Schahfer Generating stations, which Mr. D. Garrett included in his depreciation calculations. The OUCC's recommended depreciation accrual rates produced a reduction of approximately $8.9 Million from the rates recommended by Mr. Spanos. Pub. Ex. 5 at 6. Industrial Group Witness Andrews also recommended changes to Mr. Spanos's depreciation rates that would have produced a reduction from NIPSCO's proposed rates of $11.1 Million. IG Ex. 3 at 4. On cross-answering, Mr. Andrews opposed Ms. Armstrong's proposal to include the CCR decommissioning costs in NIPSCO's approved depreciation rates. IG Ex. 5 at 2.

The Settlement provides that NIPSCO's proposed depreciation accrual rates should be approved with the following exceptions and requirements:

- The amortization period for retired coal-fired generating units and the regulatory assets resulting from regulatory accounting authorized by the 45159 Order shall be extended to conclude June 30, 2034. This produces a reduction of approximately $26 Million in depreciation expense and an additional reduction of approximately $8.8 Million for the amortization of the regulatory asset resulting from the retirement of Schahfer Units 14 and 15.
- Pro forma depreciation expense will be increased approximately $9.8 Million to reflect additional demolition costs for Schahfer and Michigan City.
- NIPSCO will move to stay Cause Nos. 45700 and 45797, and upon Commission approval of all terms of the Settlement Agreement, NIPSCO shall move to dismiss both cases. In the event the Settlement is not approved in its entirety and with respect to NIPSCO's recovery of costs in relation to the projects proposed in Cause No. 45797, the non-NIPSCO parties in Cause No. 45797[14] agree to not object on the basis of the timeliness of the Petition in that Cause or issuance of a Commission order in that Cause, to recovery of costs incurred by NIPSCO after June 1, 2023, in relation to the projects proposed in that Cause. In the event the Commission rejects the Settlement, NIPSCO will move to lift the stay in those proceedings, and except as otherwise agreed to above with respect to Cause No. 45797, litigation will resume in both Causes, with all parties able to take any position in the Causes as may be justified by the law and the facts and that are not inconsistent with the terms of the Settlement.
- Depreciation rates for non-coal-fired generation assets shall be reduced, to produce an additional $9.5 Million reduction.

As required by the Settlement, Ms. Shikany sponsored the depreciation accrual rates that reflect these changes to NIPSCO's as-filed depreciation accrual rates in Petitioner's Exhibit 3-S, Attachment 3-F-S.

Ms. Whitehead stated a key part of the over $100 Million reduction in revenue requirement is the Settlement terms reducing depreciation expense and extending the coal amortization period. She explained that the Settling Parties agreed to an increase in depreciation expense to recognize demolition costs but that increase reflects a corresponding agreement to stay and ultimately dismiss two federal mandate proceedings pending at the Commission in Cause Nos. 45700 and 45797, which could have resulted in tracking those costs. In its direct case, NIPSCO had already proposed to change its depreciation methodology to mitigate the requested rate increase. She said all these reductions in expenses result in a very large decrease in cash flow available to NIPSCO, which increases the need to finance expenses and capital investments. Ms. Whitehead further explained that the Settlement Agreement reflects NIPSCO's agreement to these various terms, which, from NIPSCO's point of view, link directly to the ultimate agreement on ROE. Pet. Ex. 2-S at 5.

Ms. Whitehead said the $9.8 Million increase in depreciation expense for Schahfer and Michigan City relates to costs proposed for recovery in Cause Nos. 45700 and 45797 under Ind. Code ch. 8-1-8.4, totaling approximately $93 Million. She explained that assuming approval of the Settlement Agreement, all costs sought for recovery in those proceedings will instead be addressed in base rates. The Settlement also provides that NIPSCO will not file federal mandate cases pursuant to Ind. Code ch. 8-1-8.4 to recover costs to satisfy any asset retirement obligations

[14] This includes the OUCC, Industrial Group, and CAC.

associated with coal-fired generation. Instead, NIPSCO will debit FERC Account 108 for reasonable and prudent costs incurred for removal costs associated with coal-fired generation per the FERC Uniform System of Accounts, which entry will be reflected in future depreciation studies. NIPSCO will seek to adjust its future depreciation studies to reflect reasonable and prudent retirement costs.

The Settlement also provides for the following changes to NIPSCO's proposed amortization expense:

- The Cause No. 45159 regulatory asset amortization expense will be adjusted by an $8.22 Million annual reduction, based upon an issue identified by Mr. Gorman.
- There will be a $1.7 Million annual reduction from moving the amortization periods for COVID and Rate Case Expense regulatory asset balances from two to four years.
- There will be a $3.1 Million annual reduction from moving the amortization period for federal mandate cost adjustment ("FMCA") and TDSIC regulatory asset balances from four to seven years.

At the end of all amortization periods, the Settlement provides that NIPSCO will make a compliance filing to remove the amortization from the revenue requirement and will adjust rates accordingly.

Industrial Group Witness Gorman explained that per Sections 3(a) and 3(b) of the Settlement Agreement, the Settling Parties agreed to numerous changes to NIPSCO's proposed depreciation and amortization expense. Among these are a reduction of $9.5 Million in depreciation expense due to adjustments to the depreciation rates for non-coal-fired generation consistent with adjustments proposed by the Industrial Group and the OUCC; a total reduction of about $4.8 Million annually due to the modification of the amortization period for several regulatory assets; and an annual reduction of $8.22 Million in amortization expense for regulatory assets established in Cause No. 45159. Mr. Gorman added that the depreciation expense was further reduced by about $26.0 Million by adjusting the recovery period for remaining coal-fired generation units as initially authorized in the 45159 Order to expire on June 30, 2034. IG Ex. 6 at 4.

The Settling Parties also agreed that regulatory accounting for cost of removal for NIPSCO's coal-fired generation-related assets should be approved as outlined in Petitioner's Exhibit 3. Specifically, Ms. Shikany testified as follows:

> Q. With cost of removal removed from the regulatory asset, how are the closure costs of Schahfer being accounted for?
>
> A. The estimated costs of removal associated with the retired units will be collected through depreciation rates applicable to the same coal-fired generation FERC assets remaining in service at Schahfer and Michigan City. As costs are incurred, NIPSCO will debit FERC Account 108, Accumulated Depreciation, for those actual costs, consistent with the FERC Uniform System of Accounts. Subsequent

depreciation studies will continue to include cost of removal costs for all coal-fired generation assets until all coal units are retired.

Q. What happens if the incurred cost of removal is different than the amounts previously collected through depreciation rates once all coal-fired generation assets are retired?

A. Under normal circumstances, the estimated cost of removal collected remains in the same FERC account as the asset while the asset was used and useful. With NIPSCO's planned retirement of the entire coal-fired generation fleet by 2028, not all demolition and closure activities will be completed by the retirement date, meaning once retired, there will be no assets left in the coal-fired generation FERC accounts.

FERC Account 108 states:

> at the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance. When retirement, costs of removal and salvage are entered originally in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder.

In the future and through the completion of all coal-fired generation closure costs, all coal-fired generation retirement activity is planned to be recorded to the related coal-fired generation FERC accounts as a debit to FERC Account 108. This practice will remain in effect as long as a coal-fired generation assets remain in service.

At the point in which the final coal-fired generation assets are retired, the net book value of those final assets will be reclassified to a regulatory asset as described in Cause No. 45159. The effect of this movement will leave a residual FERC Account 108 balance representing either collections of cost of removal in excess of retirement activity or a balance representing retirement spend in excess of cost of removal collected. FERC Account 108 balances are normally associated with a corresponding FERC Plant-in-Service account. As there will no longer be a FERC Plant-in-Service account for coal-fired generation, NIPSCO proposes to reclassify the balance to a regulatory liability in the instance demolition and remediation activities remain or a regulatory asset if demolition and remediation activities exceed cost of removal collected.

NIPSCO will continue to collect cost of removal until an ensuing rate case through the approved depreciation rates, and NIPSCO will

> continue to record demolition and remediation activities to this new regulatory liability or asset in place of the FERC Account 108. The regulatory liability or asset will be included in a future base rate proceeding and amounts will be passed back or collected from customers. This will maintain the consistency of the mechanism with OUCC Witness Blakley's stated goal not to deny NIPSCO recovery of any return "of" or "on" its investment in the coal fired generating stations.

Pet. Ex. 3 at 117-119. Further, the Settling Parties agreed to the creation of regulatory liabilities or assets, as applicable to be included in future rates upon the elimination of the appropriate FERC Plant-in-Service Account, while retaining the right of others to make any challenge permitted by law, including the prudence and reasonableness of the cost.

E. Pro Forma Net Operating Income at Present Rates. The Settlement Agreement resolved the following issues concerning pro forma net operating income at present rates:

(a) Revenues. The Settling Parties accepted approximately 50% of the proposed increase in the residential sales forecast proposed by the Industrial Group, which increases revenues by approximately $2 Million.

(b) Labor. Based upon Mr. Gorman's testimony, the Settling Parties agreed to reduce NIPSCO's proposed adjustment for vacant positions by $2.2 Million.

(c) Pension and OPEB Expense. The Settling Parties agreed to accept NIPSCO's proposed adjustment to increase Pension and OPEB Expense by a combined $15.2 Million based upon the most recent actuarial report available prior to the filing of NIPSCO's case-in-chief. NIPSCO agreed to withdraw its request for a pension/OPEB balancing account.

(d) Vegetation Management. The Settling Parties agreed to reduce NIPSCO's proposed vegetation management expense by $5.8 Million, resulting in a total annual vegetation management expense of $25.1 Million. This is NIPSCO's 2022 budgeted vegetation management expense, adjusted by a 5.20% inflation escalator, making the agreement consistent with the proposal by the OUCC and Industrial Group that set Petitioner's base vegetation management budget at NIPSCO's budgeted 2022 expense.

(e) Fuel Costs. The Settling Parties agreed the base cost of fuel proposed in NIPSCO's case-in-chief would be reduced by $25 Million. NIPSCO Witness Taylor testified that the base cost of fuel utilized for purposes of the Settlement is $367,509,634. This corresponds to an approximate $0.033674/kWh on average (or

$33.67 per mill). OUCC Witness Eckert explained that NIPSCO initially requested a base cost of fuel of $35.964 mills per kWh and the Settling Parties agreed to approximately $33.67 mills per kWh. The reduction in the base cost of fuel reflects reduced market prices of natural gas and purchased power.

(f) Schahfer Fire. The Settling Parties agreed a $1.06 Million annual O&M reduction will be made in this case and any subsequent case through June 30, 2034, to resolve all known and/or disclosed issues related to the fire at Schahfer in July 2020. NIPSCO warranted that it was "unaware of any facts that would support a claim" for disallowance of costs or expenses related to the fire not already disclosed to the Commission. This portion of the Settlement Agreement also preserves the other Settling Parties' rights to pursue further adjustments should previously unknown or undisclosed facts support additional disallowances.

(g) Other O&M. The Settling Parties agreed to further reduce O&M by a total of $4.7 Million. This reduction addresses other issues raised by the parties related to pro forma results of operations at present rates.

F. Environmental Cost Tracker. The Settlement provides that NIPSCO's proposed VCT shall be renamed the ECT and approved, using the filing methodology and frequency described by NIPSCO Witness Blissmer, except as modified by the Settlement. The only costs to be recovered through the ECT are those associated with NOx emissions allowances and variable chemical costs (estimated to be a total of $30 Million per year). The ECT will be allocated among rate classes based on energy. For Rate 526, the Settling Parties agreed to a demand-based rate design, with recovery through demand charges. NIPSCO also agreed to make good faith efforts to monetize unused NOx allowances, with 100% of benefits passed to NIPSCO customers through the ECT; to re-evaluate procurement practices; and to report on monetization in each ECT tracker filing. Rather than being tracked, the costs associated with generation maintenance and outages originally proposed by NIPSCO as part of the VCT will instead remain embedded in base rates in the amount estimated by NIPSCO in its case-in-chief of approximately $72 Million. For the costs that will be included in base rates, the Settlement provides that these costs will be allocated in the same manner that they were allocated in Cause No. 45159 to maintain the "status quo" regarding allocation, which includes both a demand- and energy-based allocation component. NIPSCO Witness Whitehead and Industrial Group Witness Dauphinais both explained that the costs moving from the originally proposed VCT back into base rates would be allocated to customers on the same basis as they currently are, pursuant to the 45159 Order, which has both an energy- and demand-based component. Pet. Ex. 2-S at 10 and IG Ex. 7 at 8.

The ECT filing methodology and frequency was described by NIPSCO Witness Blissmer. The filing will be semi-annual and based upon actual historical costs. The charge will be calculated on a per kWh basis (except for Rate 526 per the Settlement Agreement). Actual costs recovered through the rider would be deferred commencing with the approval of Step 1 rates until they are recovered through the rider. The first filing is expected to be in March 2024, seeking to recover

costs incurred from the effective date of Step 1 rates through December 31, 2023. This first rider would be expected to take effect in July 2024. The second filing would then be in September 2024, recovering actual costs incurred from January 1, 2024 through June 30, 2024. The filings would follow semiannually in March and September thereafter. Pet. Ex. 4 at 33-34.

As proposed in NIPSCO's case-in-chief, NIPSCO will not implement cost recovery under the ECT immediately upon approval. Instead, NIPSCO will begin to incur costs in September 2023 but will defer recovery into 2024, which will result in rate implementation in the summer of 2024, thereby spreading out the rate increase over three (rather than two) steps—September 1, 2023; March 1, 2024; and approximately July 1, 2024. Ms. Whitehead sponsored Attachment 2-S-A, the proposed form of tariff for the ECT, along with Appendix K, which replaces the proposed forms she sponsored in her direct testimony for the VCT. Pet. Ex. 2-S at 10-11.

NIPSCO Witness Taylor presented the Proposed Rate Class Revenue Increase with ECT. Pet. Ex. 19-S, Table 2 at 10.

Industrial Group Witness Dauphinais testified that the settled terms regarding the new ECT are reasonable. He said the greatly reduced scope of the new tracker addresses the concerns he raised in his direct testimony about the relative merits of moving the proposed costs from base rates into a tracker. For the costs that are remaining in base rates, the agreement to retain the same cost allocation basis that was used in Cause No. 45159 preserves the status quo, consistent with the cost of service study approved by the Commission in that case. IG Ex. 7 at 8. Mr. Dauphinais addressed this issue in his direct testimony, arguing that most of the cost types that NIPSCO was proposing to recover in the VCT (now ECT) were previously recovered, and still should be recovered, on a demand basis. IG Ex. 2 at 24-25.

Walmart Witness Kronauer also testified that he supported the ECT Rate 526 cost allocation set forth in the Settlement Agreement. He explained that Walmart agrees with Mr. Dauphinais' assessment that because most of the cost types recovered from the ECT are fixed costs, they are more appropriately recovered through demand charges for Rate 526. Walmart Ex. 2 at 6.

G. <u>Phased Rate Implementation</u>. In addition to the mitigation resulting from the implementation of the ECT, the Settlement provides for the implementation of at least two steps of the rate increase as proposed in NIPSCO's case-in-chief. The Settlement provides that Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023, and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of June 30, 2023. NIPSCO will provide all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All parties to

this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

The Settlement provides for a similar treatment for Step 2. The Settlement provides that Step 2 rates should be implemented on or about March 1, 2024, and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The Settlement provides that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023, and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2023. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

The Settlement also provides for possible interim steps between Steps 1 and 2 in the event either Dunn's Bridge I or Indiana Crossroads Solar are not fully placed in service by June 30, 2023, but come into service by December 31, 2023. In rebuttal testimony, Mr. Campbell described that it was possible either or both projects might be delayed beyond Step 1 rates. He explained that, in that event, if a portion of either of the projects is installed, interconnected, and producing energy (i.e., used and useful), NIPSCO will certify that portion as being in service for Step 1. Pet. Ex. 11-R at 26-27. Ms. Shikany testified that an interim step would nevertheless be necessary to mitigate the continued accrual of Post In Service Carrying Charges. Pet. Ex. 3-R at 5-7. This additional step compliance filing will be based on the addition to rate base and amortization expense for Dunn's Bridge I or Indiana Crossroads Solar (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service. The rates would take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections.

H. <u>Cost of Service, Rate Design, and Rate 831/531 Modification Settlement</u>. The Settlement is comprehensive in that it resolves the revenue requirement, rate implementation questions, and all cost of service and rate design issues, including the Rate 831/531 Modification Settlement. All Settling Parties have agreed to support or not oppose adoption of the Rate 831/531 Modification Settlement. The Settlement Agreement proposes further enhancements to the Rate 831/531 Modification Settlement by correlating future reductions in Tier 1 load to reductions in the costs of legacy coal assets reflected in NIPSCO's base rates while continuing to move Rate 531 cost allocation closer to the cost of service. Also, all parties not signatories to the Rate 831/531

Modification Settlement retain all rights in future proceedings to take any position with respect to cost of service and Rate 531 issues.

The Settlement acknowledges that, as presented in NIPSCO's case-in-chief and rebuttal, residential rates under Rate 511 are being subsidized by several other rate classes, including, but not limited to, Rate 520 through Rate 533. For this reason, the Settlement Agreement proposes to mitigate a portion of this subsidy. The reduction in annual revenue (i.e., the approximately $103.2 Million of annual revenue below NIPSCO's as-filed case) will be allocated: first, to maintain Rate 531 at cost of service based on 180 MW of allocated demand as reflected in the Rate 831/531 Modification Settlement; second, 25% of the remaining amount for subsidy reduction; and third, the 75% remaining amount allocated on an across-the-board basis. Because Rate 831/531 is being brought to parity at 180 MW of allocated demand, it will not receive either a reduction to reduce subsidies (the 25% portion) or a reduction on an across-the-board basis (the 75% portion). Rate 811 rates will participate in the across-the-board reduction (the 75% portion). The Settling Parties agreed that rates will be designed so that no rate class that is currently being subsidized will move to subsidizing other rates, and no rate that is currently subsidizing other rate classes will move to being subsidized by other rates. Regarding Rate 526, considering that significant amounts of demand costs are being recovered through the energy charge, the Settling Parties agreed the revenue reduction as a result of the Settlement that is allocated to Rate 526 will be used to reduce the energy charge until all energy and demand components of Rate 526 match NIPSCO's energy/demand cost of service levels.

OUCC Witness Boerger testified that the three-step approach represents a fair approach to allocating the revenue reduction achieved as part of this Settlement Agreement. He said the significant reduction in overall revenue achieved in the Settlement allows for a higher share of the reduction to be allocated to customer classes paying rates above parity, while also providing for significant reductions in NIPSCO's proposed rates for all customer classes, including residential customers, and allowing the terms of the Rate 831/531 Modification Settlement to remain in place. For these reasons, the OUCC is satisfied these provisions represent a reasonable resolution of revenue reduction allocation. Pub. Ex. 17 at 2.

Walmart Witness Kronauer testified that he supported the revenue allocation set forth in the Settlement Agreement. He said while the Settling Parties did not adopt the proposal from his direct testimony specifically, the revenue allocation set forth in the Settlement Agreement essentially adopts the proposal in concept. Providing for a subsidy reduction by using 25 percent of the overall reduction in annual revenue (as opposed to Walmart's recommended 50 percent), after establishing Rate 531 at parity, is a reasonable compromise that benefits all classes while moving no class from a subsidized position to a subsidizing position or vice versa. Walmart Ex. 2 at 3-4. Settlement witnesses for NIPSCO, the Industrial Group, and NLMK provided further support for the reasonableness of the cost of service and subsidy mitigation provisions. Pet. Ex. 19-S at 2-5; IG Ex. 7 at 2-3, 6-7; NLMK Ex. 2 at 2-3.

NIPSCO Witness Taylor presented the settlement revenue apportionment and class rate increases in Attachment 19-S-A. Pet. Ex. 19-S. Table 1 in his settlement testimony shows the mitigation of interclass subsidies from NIPSCO's case-in-chief proposal to the Settlement. *Id.* at 5. He also presented Attachment 19-S-B which shows detailed calculations for each rate component of each Rate Schedule, as well as how the targeted total rate schedule revenue will be

achieved using the proposed rates and volumes. Further, Attachment 19-S-B provides a presentation of the transition of revenues at current rates and existing 800 series rate classes to the proposed revenues at the 500 series rate classes. Mr. Taylor also presented Attachment 19-S-D as a new version of Attachment 19-H from his direct testimony which provides the updated tracker allocators that result from the Settlement changes to cost of service and revenue mitigation.

The Settlement Agreement also provides that the Industrial Group will not pursue its proposal for voltage-adjusted FAC and revised allocation for renewable resources in this case. All Settling Parties retain all rights in future proceedings to litigate these issues.

With regard to cost of service methodology, the Settlement Agreement adopts the terms of the Rate 831/531 Modification Settlement, which provides for use of 4 CP for production assets in this case. The Settlement Agreement provides that in its next electric base rate case, NIPSCO will prepare distinct 4 CP and 12 CP cost of service analyses for purposes of allocating production-related demand costs and make each analysis available to all parties in the case. NIPSCO retains the right to determine which cost of service analysis to propose in its case-in-chief, and all other parties will have the right to take any position with regard to cost of service in that case.

The Settling Parties agreed to support or not oppose adoption of the Rate 831/531 Modification Settlement, including the terms relating to the firm service commitments of customers in the class. The current Rate 831 customers agreed to enter into new contracts for an aggregate 170 MW of firm demand under Tier 1 of Rate 531, thereby foregoing the opportunity to reduce firm commitments more substantially, with costs being allocated to the class based on 180 MW. The Settlement Agreement recognizes that further reductions in Tier 1 commitments likely would occur in the future. The Settling Parties agreed to continue to narrow the differential between Rate 531 allocated demand and actual contract demand, but in no event shall that narrowing be accomplished by requiring a Rate 531 customer to increase its Tier 1 demand involuntarily. In support of the Rate 831/531 Modification Settlement, both NIPSCO and the Industrial Group presented testimony explaining the significance of stability in firm load for large industrial customers for purposes of capacity planning by NIPSCO during the transition from legacy coal-fired plants to a portfolio of replacement capacity, and the diminishing role of firm industrial demand as the costs of legacy assets are reduced and removed from rates. Pet. Ex. 2 at 42-48; IG Ex. 2 at 13-19.

The Settlement Agreement provides further detail as to how future reductions to Tier 1 load and cost allocations to Rate 531 as contemplated in the Rate 831/531 Modification Settlement will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates. Under that process:

(a) the relevant comparison is between end of test year in the prior rate case and end of test year in a subsequent rate case;

(b) the measure of costs for legacy coal assets includes capital balances for coal assets, as well as fixed O&M, coal inventory, and other base rate inclusions;

(c) the starting point is the proposed Rate 531 tariff terms and conditions, 180 MW of allocated Rate 531 class demand, and 170 MW of aggregate contract demand. The eventual end

point, based on the current composition of the class, is 70 MW of both Tier 1 class demand and actual contract demand, with future proportional adjustments reducing the starting 110 MW differential between the class demand and the end point;

(d) successive future adjustments will involve both reductions in Tier 1 class allocations and contract demand commitments to progressively narrow the spread between allocated demand and actual contract demand for the class; and

(e) the methodology assumes existing class composition throughout legacy coal asset recovery period, subject to an agreed process to address any material changes in circumstance.

Nothing in the Settlement Agreement obligates an existing Rate 831 class member to increase its Tier 1 contract demand commitments in the future. In the event of any material change of circumstances affecting the composition of the class or the class load, the signatories to the Rate 831/531 Modification Settlement and OUCC agree to meet and confer, with the following clarifications: (a) no class member is prohibited from exiting the rate upon expiration of the contractual term; (b) existing tariff provisions on modifying commitments in the event of a facility closure remain in force; (c) in the event a class member exits the rate, the allocated demand and total contracted demand for the class will be reduced correspondingly provided that the exiting customer is migrating to another rate schedule with a like firm demand or the exit from Rate 531 is attributable to a facility closure or material reduction in load; (d) in the event that a class member increases Tier 1 load then other class members not at tariff minimum may decrease Tier 1 commitments correspondingly to maintain class load at agreed levels; (e) in the event a new customer joins the rate class then existing customers with firm demand above the tariff minimum will be permitted to reduce Tier 1 commitments so long as the class load is maintained at the agreed levels; and (f) recognizing that not all contingencies can be anticipated and addressed in advance, any signatory to the Rate 831/531 Modification Settlement or the OUCC may initiate discussions in the event of a material change of circumstances and, absent agreement, may submit the issue for resolution by the Commission.

Dr. Boerger explained the terms of this subsection prevent proportional reductions in Tier 1 cost responsibility greater than the proportional reduction in costs of legacy coal assets. Noting there are several specific implementation provisions and caveats found in this language, he said the nucleus of this section reflects agreement that Rate 831/531 customers will continue to help fund the costs of NIPSCO's legacy coal assets, until such costs are no longer found in NIPSCO's base rates. He testified while the OUCC sought in its direct testimony to obtain a higher level of ongoing funding from Rate 831/531 customers for NIPSCO's legacy coal assets, the provisions in this subsection represent a reasonable compromise of positions and will provide a greater degree of certainty that the OUCC expects will benefit all customer classes. He explained he was happy to see provisions in Section B.7(g) referencing commitments to "meet and confer" in the event of material changes in circumstance and "initiate discussions," recognizing that "not all contingencies can be anticipated." Given the unusual nature of Rate 831/531, he expects such commitments to communication and collaborative work will be helpful moving forward. Pub. Ex. 17 at 2-3.

The provisions relating to Rate 531 were further supported by settlement testimony from current Rate 831 customers. Mr. Dauphinais testified the terms largely preserve the status quo, with modest reductions in Tier 1 commitments and a closer alignment between cost-allocation

demand and actual demand. He stated the treatment of future Tier 1 adjustments is reasonable and beneficial to NIPSCO, other rate classes, and Rate 531 customers. IG Ex. 7 at 3-6. Mr. Radigan testified that these provisions collectively aim to provide predictability to all customers and Rate 531 participants today and in future cases and explained that NLMK considers this is a fair and reasonably balanced approach to highly inter-related economic competitiveness and cost allocation concerns presented in this Cause. NLMK Ex. 2 at 5. Mr. Riberich testified that the Settlement Agreement benefits NIPSCO's customers. He explained as to U.S. Steel's specific interests, the fundamental structure of Rate 531 remains unchanged and fully recovers the settled revenue requirement associated with the class. Customer eligibility for the rate, how the service tiers will work, and how Large Industrial Customers will contribute to NIPSCO's revenue requirement have not changed from what NIPSCO originally proposed in its Petition in this Cause. He said the Large Industrial Customers proactively agreed to commit to a set amount of Tier 1 Firm Contract Demand elections and a calculated demand rate that fully recovers the required settled revenue requirement for Rate 531. Without such a commitment, the settled revenue requirement as it relates to Rate 531 is meaningless, because customers cannot be forced to take a set level of firm demand. U.S. Steel Ex. 2 at 3-4.

The Settlement also addresses several rate design issues unrelated to Rate 531. The Settlement adopts the customer charges proposed by NIPSCO, except NIPSCO's existing monthly charge for Rate 511 shall be increased to $14.00 and the existing monthly charge for Rate 521 shall be increased to $32.50. Witnesses explained that through compromise, the Settling Parties agreed to increase the monthly residential customer charge by $0.50 to $14.00, which was NIPSCO's monthly residential customer charge prior to the 45159 Order. In addition, the Settling Parties agreed to increase the small commercial (Rate 521) monthly customer charge by $1.00 to $32.50. Pub. Ex. 16 at 13; Pet. Ex. 2-S at 12; Pet. Ex. 19-S at 7.

In response to CAC testimony, NIPSCO agreed to collect data on residential customer housing types to identify multi-family customers and analyze cost differentials between single- and multi-family residential customers. NIPSCO will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, NIPSCO will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested stakeholder the results of its analysis.

As part of the Settlement, and to address issues raised by the Industrial Group in its direct testimony, NIPSCO agreed that as part of preparing the cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to this rate or the creation of another rate for current customers in Rate 532 is appropriate.[15] This review will include a review of the appropriate minimum demand level for participation in Rate 532 and demand blocks and demand and energy charges. NIPSCO will make this information available to any member of this rate class and/or their

[15] NIPSCO made similar commitments to study operational and usage characteristics of each of the four RV Group members to determine if a new or adjusted rate schedule is appropriate prior to NIPSCO filing its next electric base rate case, as reflected in Joint Exhibit 1, Addendum B, paragraph 5.

consultants who request such information.[16] Finally, the Settlement provides that the percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511.

I. Low Income Program. The Settlement provides that NIPSCO will withdraw its proposed Low Income Program. However, under the Settlement, NIPSCO retains the right to seek approval of a low income program in the future. In recognition of concerns expressed by the OUCC and CAC, NIPSCO agreed to contribute below the line (i.e., not to be recovered through rates) a total of $400,000 to Indiana Community Action Association. These contributions will be made in $100,000 increments in calendar years 2024, 2025, 2026, and 2027. Ms. Whitehead explained that NIPSCO made this decision primarily based on disagreement among the parties as to whether a non-by-passable, opt-in, or opt-out program design was appropriate. She said that NIPSCO's annual contributions to the Indiana Community Action Association are intended to enable many more low-income residents to get necessary health and safety work completed on their homes, which is a prerequisite for qualifying for home weatherization. Pet. Ex. 2-S at 15-16; see also Pub. Ex. 16 at 14. On cross-examination, Ms. Becker explained that these funds will be used to improve conditions at homes that would otherwise be eligible for federal weatherization dollars—improvements such as repairing a leaking roof. As such, she testified that NIPSCO's contribution would have a material and positive effect on providing access to this federal program. Tr. at A-97 to -98.

J. Other Relief Requested by NIPSCO. Paragraph B.14. of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement will be adopted as proposed by NIPSCO's case-in-chief, as modified in its rebuttal testimony. This type of provision is common in Settlement Agreements before the Commission and reasonably identifies the starting point for purposes of the ratemaking and accounting authority being granted. The Commission notes that Petitioner clarified on rebuttal that its requested relief does not include approval of a tax rate change rider. Instead, Petitioner's request is for deferred accounting authority and that it be permitted to request approval of a rider outside of a general rate case, at which time all interested parties would retain the right to oppose such approval (should it be requested) on any grounds other than that it should not be approved outside of a general rate case. Petitioner's Ex. 3-R at 33. In general, the relief sought by NIPSCO is summarized in Paragraph 5 of this Order.

K. Typical Bill Comparison. Ms. Whitehead presented Attachment 2-S-B, which showed the estimated impact on the average residential customer's monthly electric bill and how that compares to the estimated impact on customers in NIPSCO's case-in-chief. She said that for a typical residential customer using 668 kWh, the Step 2 rate implementation in March of 2024 plus implementation of the ECT in July of 2024 results in a total increase of 10.3%. This compares to an estimated 11.3% increase following Step 2 rate implementation and 16.5% increase following VCT implementation under NIPSCO's case-in-chief. She testified that NIPSCO believes the Settlement and resulting impact on all customers represents a reasonable, fair resolution to this case. Pet. Ex. 2-S at 21-22.

[16] NIPSCO made similar commitments to provide advance rate characteristic and cost allocation information available to the RV Group prior to NIPSCO filing its next electric base rate case, as reflected in Joint Exhibit 1, Addendum B, paragraph 6.

Mr. Taylor presented the typical bill impacts for residential customers on Attachment 19-S-C, which contains two bill impact analyses: (1) with the base rate increase and the inclusion of the ECT, and (2) the base rate increase, without the ECT. Pet. Ex. 19-S at 10.

L. <u>Addenda to the Settlement Agreement</u>. Ms. Whitehead explained that Addendum A contains separate terms between NIPSCO and IMUG, which were reached to address IMUG's concerns and allowed them to not oppose the Settlement. Likewise, Addendum B contains separate terms and commitments by NIPSCO to and with the RV Group, which were reached to address the RV Group's concerns and allowed the RV Group to sign the Settlement. Neither of the addenda have a direct base rate impact, but do, in part, respond to and address service-related concerns raised by both parties and were reasonable ways to resolve concerns, promote more effective and efficient use of electricity generally, and allow these parties to either not oppose or to sign on to the Settlement. Because there is no direct base rate impact, NIPSCO does not believe the Commission needs to take any action on the addenda. However, NIPSCO included them as addenda to the Settlement to ensure the Commission was aware of these terms and to memorialize NIPSCO's commitments to these parties and the basis for the positions to not oppose and to sign on to the Settlement. Pet. Ex. 2-S at 16-17.

Mr. Sommer testified in support of Addendum A and stated IMUG does not oppose the remainder of the Settlement Agreement. He said through negotiation, compromise, and settlement, Addendum A largely addresses the concerns and recommendations from his direct testimony. He summarized each of the sections of Addendum A, including limiting the Rate 550 increase,[17] IMUG member energy efficiency audits, sharing LED conversion expertise, and a joint effort to improve NIPSCO record-keeping for NIPSCO street light maintenance. He testified municipalities are unique from other types of NIPSCO customers in that their need for affordable electric service is critical to their ability to fulfill their public service role. He said through the provision of vital public services, municipalities are materially responsible for the wellbeing of area residents, workers, and businesses. They serve the public without any profit motivation and provide many services essential to public safety and the economic wellbeing of those who live in, work in, or visit their areas, including street lighting. He testified that because municipalities are financial closed loop public service entities, dollars saved on electric costs could be used to maintain and improve vital public services. Mr. Sommer stated in all, Addendum A promotes efficiency, public service, public safety, and economic development; yields substantial benefits to municipalities, their residents, NIPSCO and its customer; and helps avoid protracted litigation, costs and uncertainty. IMUG Ex. 2 at 2-6

RV Witness Burke discussed both service improvement commitments and the TDSIC portion of Addendum B and explained why they are reasonable and appropriate. RV Group Ex. 4-S at 3-4. He explained that not only is NIPSCO making a written commitment, including a targeted dollar amount for the RV Group, but the language also: (1) recognizes that these projects and the related TDSIC facilities can be used to serve other NIPSCO customers; and (2) places an obligation on the RV Group member applying for such a TDSIC project that the project:

[17] The commitment regarding Rate 550 is also included in Section 7(l) of the Settlement Agreement and provides: "The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511."

> …result in continued or increased energy demand or continued or increased employment by the applying RV Group member from new capital investments made within the NIPSCO service territory; (ii) support RV Group member renewable energy projects, energy efficiency and demand response, or peak load reduction projects; and (iii) any advanced or smart meter technology that will assist an RV Group member in reducing peak load. (Addendum B, Page 2, Para. 9).

Id. at 5. Mr. Burke stated these obligations are specific and beyond what is required under the TDSIC statute but designed to encourage actions by the RV Group to retain or increase energy and/or employment levels and make capital investments in NIPSCO's service territory here in the State. He testified that the TDSIC section is not intended to be a preapproval request of the Fund or any of the projects discussed and anticipated but does commit both NIPSCO and the RV Group members as provided in Addendum B. *Id*. at 6.

M. Public Interest. Ms. Whitehead testified that all the provisions of the Settlement are interrelated, and the Settlement represents a diligent effort by all Settling Parties to reach a comprehensive result. Citing to 170 IAC 1-1.1-17, Ms. Whitehead described the Commission's policy regarding settlement, which she said is consistent with the general public policy favoring settlement. Pet. Ex. 2-S at 18.

The Settlement Agreement provides that if following its examination, the Commission finds it to be in the public interest, the Settlement should be approved in its entirety and without change or conditions unacceptable to any Settling Party. Ms. Whitehead testified that the Settling Parties' ability to negotiate a settlement in this proceeding representing various customer segments and diverse interests is strong evidence that the Settlement is in the public interest. She testified the Settlement resolves complex, divisive, and controversial issues surrounding revenue requirement, cost allocation, and other significant issues. Moreover, the Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost. She said NIPSCO and the other Settling Parties invested significant time and effort to reach a "global" settlement of this kind. In so doing, the Settling Parties explicitly agreed that the Settlement accounts for the overall level of risk presented to NIPSCO by the Settlement. Per Ms. Whitehead, NIPSCO believes this is important because it only agreed to the terms based on the Settlement as a whole, and it expects to receive the full value of and benefits from the Settlement. Pet. Ex. 2-S at 19-21.

Mr. Eckert testified the Settlement Agreement balances the interests of NIPSCO and ratepayers. He said the Settlement Agreement is a product of intense negotiations, with each party offering compromise to challenging issues. He said that while the Settlement Agreement represents a balance of all interests, given the number of benefits provided to ratepayers as outlined in the Settlement Agreement and described in his settlement testimony, the OUCC, as the statutory representative of all ratepayers, believes the Settlement Agreement is a fair resolution, supported by evidence, and should be approved. Thus, the OUCC recommends the Commission find the Settlement Agreement to be in the public interest and approve it in its entirety. Pub. Ex. 16 at 2, 15.

On behalf of the Industrial Group, both Mr. Gorman and Mr. Dauphinais testified that in addition to individual components of the agreement, the Settlement as a whole provided a fair and reasonable resolution to the issues raised in the proceeding. Mr. Dauphinais emphasized that the Settlement was negotiated in good faith by the parties, all of whom were represented by counsel and had the benefits of the parties' respective evidentiary submissions and extensive discovery. Mr. Gorman likewise testified that the Settlement was the result of arm's length negotiations conducted in good faith by parties with a range of diverse interests, which were sometimes complementary and sometimes contradictory. He explained that despite the complexity of the issues, the parties were able to achieve consensus on the Settlement, which he believes represents a reasonable resolution to the case and appropriately balances the various interests of the parties in a manner consistent with sound ratemaking principles. IG Ex. 6 at 6 and IG Ex. 7 at 9.

RV Group Witness Burke testified that he supported the Settlement Agreement, including Addendum B, as being in the public interest and recommended that it be approved without modification. RV Group Ex. 4-S at 6.

Walmart Witness Kronauer explained why he believes the Settlement Agreement is consistent with the public interest. He stated the Settlement represents significant compromise between the parties on the complex issues in this case that will produce an opportunity for NIPSCO to earn sufficient revenues to provide adequate service to its customers at a fair return while also protecting those customers, and the Indiana public, from unreasonable rate increases and impacts. Walmart Ex. 2 at 6-7.

Mr. Radigan testified that NLMK fully supports Commission adoption of the Settlement Agreement in its entirety. NLMK Ex. 2 at 2.

U.S. Steel Witness Riberich testified that approval of the Settlement Agreement is consistent with the public interest because the Settlement represents a comprehensive resolution of all the issues in this proceeding by the Settling Parties, including NIPSCO's revenue requirement, cost of service, and rate design. He said the Settlement Agreement provides NIPSCO with an opportunity to earn sufficient revenues to provide reasonably adequate service and a fair return on its investment. It also balances the interests of the utility's current and future customers in receiving reasonable service at a fair cost. U.S. Steel Ex. 2 at 5.

8. <u>Opposition to Settlement Agreement</u>. Mr. O'Connell testified as to MIUG's opposition to the Settlement Agreement. MIUG Ex. 3. He explained what he considered to be arbitrary barriers in the proposed Rates 532 and 533 because they were created without a clear methodology and are primarily the result of past NIPSCO rate case settlements. He said these arbitrary barriers directly cause certain transmission customers to pay significant premiums on their electric services by forcing them on to the proposed Rate 526 services. He said the proposed Rate 526 and current Rate 826 allocates distribution system charges to at least two transmission customers who are not connected to NIPSCO's distribution system; whereas, the proposed Rates 531, 532 and 533 only allocate transmission and sub-transmission charges to similarly situated transmission customers. He explained, using cost causation principles, NIPSCO should not allocate its distribution system costs to any transmission-only customers, as these customers do not benefit from NIPSCO's distribution system, nor were they the direct or proximate cause for the development of the distribution system. He also said, under the proposed Rate 526, a

hypothetical transmission customer with a peak demand of less than 10,000 kW will be allocated significant distribution service charges, while a similarly situated customer on the proposed Rates 531, 532, or 533 who happens to have a peak demand of over 10,000 kW will pay no such distribution service charges.

Mr. O'Connell recommended the Commission modify NIPSCO's proposed Rates 532 and 533 for transmission or subtransmission by removing, or significantly reducing, the minimum peak demand requirement to 2,000 kW or a value that is supported by a reasonable and just calculation methodology, to allow more transmission and subtransmission customers access to these rates and to better align with the principles of cost causation. He suggested NIPSCO's proposed Rates 532 and 533 be modified by removing the requirement for customers, at their own expense, to furnish, supply, install and maintain, beginning at the point of delivery, all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the Premise of the Customer. MIUG Ex. 3 at 3, 9.

He also recommended NIPSCO reincorporate the former Rider 775 and offer it to all Rate 532 and 533 customers. He testified adding this Rider would reduce the risk of NIPSCO procuring excess generation that could potentially be stranded in the future if those Rider customers chose to self-generate or otherwise leave the NIPSCO system. He noted multiple MIUG members recently expressed interest in self-generation, and he believes other Transmission customers will pursue similar options due to increasing rates, unfair rates compared to slightly larger competitors, and the continued misallocation of distribution system capital costs to Transmission customers.

Mr. O'Connell filed separate opposition testimony to Rate 531 and Rider 577. He identified what he considers to be arbitrary or discriminatory barriers in NIPSCO's proposed Rate 531 as related to FERC Order No. 888. He discussed FERC jurisdiction, stating his objective is to clarify the regulatory consequences of Rate 831/531 as it is designed to arbitrarily block Qualified Customers from accessing Tier 2 and Tier 3 of this rate. MIUG Ex. 2 at 3, 10-23. He recommended expanding the scope of customers eligible for Rate 531 to include "qualified customers," which he defined as any customer with at least 1 kW of demand. *Id.* at 9. Mr. O'Connell provided additional information on how MIUG members are considering reducing load on the NIPSCO system without impacting their industrial production. *Id*. at 5-6. He also discussed why he thinks proposed Rate 531 violates various Indiana statutes. *Id*. at 8-9, 23-28.

Mayor Parry explained Michigan City's opposition to the Settlement Agreement. He expressed concern with the impact of the 10.5% increase to the average electric utility bill for Michigan City residents. He said he did not find that the Settlement Agreement addressed his concerns about affordability and the impact of high commercial electricity rates on his efforts to induce businesses to locate and stay in Michigan City. He explained why he believes that the 9.80% ROE referenced in the Settlement Agreement does not send the right message to NIPSCO management. He also explained why he has not seen any sign that NIPSCO is committed to improving its customer satisfaction ratings. Michigan City Ex. 2.

9. Settlement Rebuttal. Responding to Mayor Parry's concerns about affordability, Ms. Whitehead explained the steps NIPSCO took during the preparation of the case to mitigate bill impacts. She said that the Settling Parties further built upon the pre-filing rate increase mitigation steps, which resulted in an additional reduction in revenue requirement of over $103

Million. Ms. Whitehead stated that affordability has been addressed by the Settlement terms, which were negotiated with the consumer parties. NIPSCO estimates that the residential bill increase for an average NIPSCO customer consuming 668 kWh has been reduced from 16.5% (in NIPSCO's case-in-chief) to 10.3% (in the Settlement), which is broken into multiple steps over several months. She further explained the bill increase agreed to as part of the Settlement Agreement also resolves issues related to recovery of demolition costs for Schahfer and Michigan City under Ind. Code ch. 8-1-8.4 totaling approximately $93 Million for which NIPSCO was seeking recovery in other cases. So, not only does the Settlement produce a revenue requirement in this case that is approximately $103 Million less than NIPSCO requested, but the Settlement also eliminates any further need for recovery of the federal mandate costs, which would have been in addition to the outcome of the rate case if not included in the Settlement. Pet. Ex. 2-S-R at 1-5.

In response to Mayor Parry's suggestion that NIPSCO shareholders should participate in the burden of transitioning to renewable generation, Ms. Whitehead explained that what Mayor Parry seeks is inconsistent with all the CPCNs previously issued by the Commission for projects associated with NIPSCO's renewable transition. She said those orders found that the public convenience and necessity requires those projects and that the costs are authorized to be included in NIPSCO's rate base and therefore recovered from customers. *Id*. at 6.

Ms. Whitehead also responded to Mayor Parry's concerns regarding the 9.80% ROE. She said that balancing the interest of all stakeholders, the Settling Parties agreed on the ROE of 9.80%, which was a significant reduction from the ROE supported by NIPSCO's expert witness. NIPSCO and the other Settling Parties invested significant time and effort to reach a "global" settlement of this kind. She stated in so doing, the Settling Parties explicitly agreed that the Settlement accounted for the overall level of risk presented to NIPSCO by the Settlement. She explained why the Commission should not make a reduction to the ROE as it did in Cause No. 45159, noting the difference in circumstances. She said that here, the Settling Parties did not agree to the revenue requirement and leave open the status of Rate 831/531. Instead, the Settlement is comprehensive, and it is the resolution of all issues that is embodied in the agreed upon ROE of 9.80%. Thus, the agreed-to ROE in this case already reflects the Settling Parties' assumptions about any effect on ROE from approval of the 831/531 Modification Settlement. *Id*. at 6-9.

In response to Mayor Parry's concerns regarding customer satisfaction and the ROE, Ms. Whitehead explained again that they were considered in the Settlement. Pointing to her rebuttal testimony, she noted NIPSCO is implementing specific actions to help address the service reliability concerns raised by the RV Group and provided an overview of NIPSCO's efforts to utilize satisfaction measurement surveys to continue to improve residential, business, and major accounts customer satisfaction. She explained that she also provided testimony outlining NIPSCO's improvements in the 2022 J.D. Power Residential Customer overall satisfaction survey for the Midwest region of midsize utilities scoring NIPSCO at 724, which is above the group average of 719 and the highest of the Indiana electric investor-owned utilities in the segment. NIPSCO understands that there are opportunities for improvement for its business customers and believes this and NIPSCO's other customer satisfaction scoring were considered in reaching an overall agreement with the Settling Parties. *Id*. at 10-11.

Finally, Ms. Whitehead testified that NIPSCO is encouraged to hear that the Mayor is supportive of a low income assistance program and encourages the Mayor's continued support of

NIPSCO to offer meaningful bill assistance programs to low income customers. She explained that NIPSCO withdrew its proposed low income the program in this case after not being able to resolve concerns raised by some consumer parties. However, NIPSCO retained the right to seek approval of a low income program in the future and committed to continuing to work with consumer parties to address their concerns and offer meaningful low income solutions in the future. *Id*. at 11-12.

Mr. Campbell responded to the two issues raised by MIUG Witness O'Connell. With respect to Mr. O'Connell's arguments that Rate 531 should be expanded to a larger group of customers, Mr. Campbell explained why NIPSCO disagreed and did not consider such expansion to be in the best interests of its other customers. As an initial matter, he said that the Rate 831/531 Modification Settlement makes no changes to the existing Rate 831 service structure, the operating mechanics, or the eligibility requirements for that structure. He testified that Mr. O'Connell's complaint essentially challenges the ARP that the Commission approved in Cause No. 45159 and not the issues or changes presented in this Cause. Citing to Ind. Code § 8-1-2.5-6, Mr. Campbell testified that the Commission may not order material modifications to the ARP without the agreement of the energy utility. He said a change of the type that Mr. O'Connell seeks is a material modification of the ARP and NIPSCO will not agree to the change in scope of proposed Rate 531 that is being requested by Mr. O'Connell. Pet. Ex. 11-S-R at 4-6, 10-11.

Mr. Campbell explained why Mr. O'Connell's requested modification is inconsistent with the purpose of the ARP. He said the Rate 831/531 customers have agreed to a cost allocation based upon demand that exceeds their contracted Tier 1 demand; whereas what Mr. O'Connell suggests is fundamentally different—to open Rate 531 to every customer with at least one kilowatt of demand. NIPSCO has no idea how many customers might want to utilize such a structure or whether they would be willing to accept cost allocation based upon demand that exceeds the contractual commitments. In any event, he explained, the potential scope of load removed from NIPSCO's system under Mr. O'Connell's proposal could have a catastrophic cost impact for those customers who remain on standard service—including NIPSCO's residential customers. It would also turn the proposed Rate 531 into the exact opposite of what NIPSCO's approved original ARP was intended to accomplish—the preservation of a degree of firm, retail, load to ameliorate the risk of rapidly increasing costs to other customers due to a sudden departure of load from the system. *Id.* 6-9.

Mr. Campbell also explained what would occur if the modification to the ARP was to be rejected because NIPSCO was unwilling to accept the change in scope advocated by Mr. O'Connell. He said this is addressed in Paragraph C.1. of the Rate 831/531 Modification Settlement. He explained the approved ARP under which Rate 831 was implemented will remain in place, the Rate 831 customers will provide their respective Tier 1 demands so that rates can be designed for the compliance filing following issuance of the Order in this proceeding, and negotiations will commence. Those negotiations will not result in opening NIPSCO's industrial service structure to all "qualified customers" as advocated for by Mr. O'Connell, because an expansion on that scale and without certainty as to its impact is unacceptable to NIPSCO. Instead, the existing Rate 831 customers would be required to renegotiate their Tier 1 load commitments—commitments made as part of the Rate 831/531 Modification Settlement, which benefit all customers by assuring there is not a precipitous drop in Tier 1 load but rather a gradual reduction. *Id*. at 9-10.

Mr. Campbell explained that Rate 831 is bundled retail service, and Mr. O'Connell's arguments about FERC jurisdiction are incorrect. He said that even if Mr. O'Connell was correct, Mr. O'Connell's proposed solution to expand the group of eligible customers makes no sense because Rate 531 would continue to suffer the same deficiency. Mr. Campbell also disagreed with Mr. O'Connell's claims that all MIUG customers are "similarly situated" to the Rate 831 customers. He said while the Rate 831 customers have technical expertise in house, Mr. O'Connell admits that is not the case with the MIUG members and some, if not all, would need to consider contracting with a power marketer. But, he said, more importantly, Rate 831 was created to address a specific existing circumstance—a small group of five very large customers who represented approximately 40% of NIPSCO's total load, who had the ability to leave NIPSCO's system to the detriment of remaining customers and who possessed the skillset to participate in Rate 831. He said this is not the case with the MIUG members. *Id*. at 11-13.

Mr. Campbell stated any customer can consider behind-the-meter generation but that does not put that customer in the same class as a Rate 831 customer. He also disagreed with Mr. O'Connell's suggestion that any NIPSCO customer could purchase its energy from the MISO wholesale market through MISO Financial Schedules and stated Attachment A is inapplicable to Mr. O'Connell's proposed scenario. He said for Mr. O'Connell's scenario to work, the entity would need to be registered as a Market Participant, which requires additional FERC approvals. A behind-the-meter generator that is not a Qualified Facility would need to be registered by NIPSCO, acting as the Market Participant, on behalf of the Asset Owner that NIPSCO would register as a Load Modifying Resource. In addition, Mr. O'Connell's Attachment A contains a quote from a MISO presentation about behind the-meter generation that is also a Qualified Facility under the Public Utility Regulatory Policies Act, which is not what Mr. O'Connell's scenario addresses. *Id*. at 13-14.

Regarding Mr. O'Connell's claims that Rate 831 is discriminatory and in violation of Ind. Code § 8-1-2-4, Mr. Campbell noted that Rate 831 is pursuant to a Commission-approved ARP, which establishes alternative regulation notwithstanding any other law. He said, additionally, every rate in NIPSCO's approved Tariff contains eligibility requirements and therefore "discriminates" against customers who are not eligible. The question is whether the limits on eligibility are reasonable and whether the rate has been offered to all customers meeting those eligibility requirements. He explained the thresholds created and approved in the 45159 Order are reasonable because they were tailored to address the issue of concern and the particular characteristics of the Rate 831 customers. *Id*. at 15-16.

Mr. Campbell described Mr. O'Connell's claims regarding Rate 532/533, including his claims that the methodology to arrive at the thresholds in the tariff has not been disclosed. Mr. Campbell noted that NIPSCO proposed no changes to the rate eligibility thresholds in NIPSCO's existing approved Tariff. And, although only the Industrial Group opposed that proposal by proposing a reduction to the Rate 532 minimum contract demand from 15,000 kW to 10,000 kW, the Settlement makes no changes to the thresholds. Rather, as to Rate 532, NIPSCO committed to re-evaluate the contract demand and even the possibility of a new rate. Mr. Campbell stated that the methodology to arrive at these thresholds was provided in discovery to the OUCC and explains the thresholds were established in settlement to describe the customers that wished to migrate to these rates in settlement. *Id*. at 17-18.

Mr. Campbell explained the basis for the requirement that the customer own the equipment needed to transform the energy from transmission voltage. He said that this requirement is needed for the customer to be a transmission customer. A transmission customer takes service at transmission voltage and NIPSCO is not responsible for any of the equipment to transform that energy from transmission voltage to the voltage requirements of a customer. He said if NIPSCO was responsible to transform the voltage to the customer's requirements, it would no longer be "transmission" service because the customer would be receiving distribution service. *Id*. at 19.

Mr. Taylor responded to Mr. O'Connell's opposition to the Settlement Agreement regarding the cost causation and allocation of distribution service charges to Rate 526. He stated that Mr. O'Connell misunderstands NIPSCO's allocated cost of service and rate design for Rate 526. Mr. Taylor said that while the allocated cost of service allocates costs to the entire class, the fact that certain customers do not utilize the primary distribution system and certain customers do not utilize the secondary distribution system is reflected in the rate design for Rate 526 as shown in Attachment 19-S-B of Petitioner's Exhibit No. 19-S. He further explained that for the secondary system demand-related costs, the average of 12 monthly non-coincident peaks at secondary allocation factor excludes the kW demand of customers that do not utilize the secondary distribution system. He said this results in the secondary system demand-related costs for Rate 526 being allocated based on 71,896 kW at secondary voltage level, as opposed to the Rate 526 total 12-nonCP which equals 210,121 kW, or approximately 34% of the total 12-nonCP.

Mr. Taylor explained that customers on Rate 526 can take service on other tariffed rate offerings. He said Rate 526 is a rate offering provided by NIPSCO with a discounted demand charge for customer-specific peak demands that occur during off-peak periods. As such, customers can reduce their demand charges by changing their load shapes to off-peak periods. He said these customers can also elect to take service under Rate 524, which does not provide for a demand discount during off-peak periods. He also explained that a customer on Rate 826 who takes service at either primary or secondary voltages would not be eligible for service under Rates 532 or 533 if the thresholds were reduced as requested by Mr. O'Connell. He said as such, none of the members of MIUG would benefit from Mr. O'Connell's proposal. *Id*. at 6-7

10. <u>Commission Discussion and Findings</u>. At the outset, we acknowledge that NIPSCO is in the midst of a substantial generation transition from coal-fired generation to renewable generation resources. As NIPSCO has undertaken this transition, it has invested significant capital into its generation, transmission, and distribution assets—much of which has been pre-approved by the Commission. These investments are the primary driver of the revenue increase NIPSCO seeks in this case, but they are also necessary for NIPSCO to realize benefits for its customers in the longer term. Those benefits include a more reliable and resilient electrical system for the provision of electricity through a diverse set of resources that considers environmentally sustainable sources of electric generation.

Despite the complexity and number of issues raised in this proceeding, the Settling Parties reached a comprehensive agreement, as reflected in the Settlement Agreement filed in this proceeding. Although it is opposed by two parties, those joining or not opposing the Settlement Agreement and Addenda represent a wide variety of interests and types of customers, including residential, commercial, and industrial customers. A complete copy of the terms and conditions of the Settlement Agreement can be found in Attachment A to this Order (Jt. Ex. 1), while the new

depreciation rates are set forth in Attachment B (Pet. Ex. 3-S, Attach. 3-F-S) and the Redacted Rate 831/531 Modification Settlement is attached as Attachment C (Pet. Ex. 2, Confidential Attach. 2-B). These attachments are incorporated into and made a part of this Order by reference.

Settlement is a reasonable means of resolving a controversial proceeding in a manner that is fair and balanced to all concerned. The Settlement Agreement represents the Settling Parties' proposed resolution of the issues in this Cause. As the Commission has previously discussed, settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co*., 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (quoting *Citizens Action Coal. of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal. of Ind., Inc.*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including approval of a settlement must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum,* 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Public Service Co.*, 582 N.E.2d 330 (Ind. 1991)). The Commission's procedural rules require that the settlement be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreements, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreements are reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that such agreements serve the public interest.

The Commission has before it substantial evidence from which to determine the reasonableness of the terms of the Settlement Agreement on all issues, including Petitioner's rate base, methodology to be used in determining Petitioner's rate increase, allocation of the rate increase, rate design, ROE and capital structure, and the other terms of the Settlement Agreement, all of which we find are supported by the evidence and testimony presented. The Settlement Agreement, along with its attachments and the Settling Parties' testimony and exhibits, provide substantive information from which to discern the basis for the components of the increase in NIPSCO's base rates and charges under the Settlement Agreement, and we find the evidence supports that they are reasonable. We also recognize that all but two parties in this proceeding either support or do not oppose the Settlement Agreement, including NIPSCO, the OUCC, Industrial Group, NLMK, U.S. Steel, RV Group, Walmart, CAC, and IMUG. These parties represent varied and competing customer groups and interests, encompassing practically all (if not all) NIPSCO rate classes.

As discussed in Section 7 of this Order, the Settling Parties made numerous compromises to reach an agreement. NIPSCO, in its initial case-in-chief, provided evidence supporting a revenue deficiency of $395 Million, reflective of an overall 25.85% revenue increase. As shown by Paragraph B.1.(a) of the Settlement Agreement, the Settling Parties agree that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders, plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount originally requested by NIPSCO in its case-in-chief. Additionally, the Settlement Agreement also addresses cost recovery of approximately $93 Million related to

two pending federal mandate cases, which is in addition to the base rate increase NIPSCO sought in its direct case. Jt. Ex. 1, Para. B.3.(a).

Based on the evidence presented, we decline to make the modifications suggested by Michigan City and MIUG for the reasons set forth below and approve the Settlement Agreement without modification.

A. Disputed Issues. There are essentially three issues that have been raised in opposition to the Settlement: (1) whether the Settlement is reasonable notwithstanding the challenges raised by Michigan City, particularly the stipulated return on equity of 9.80%; (2) whether Rate 531 should be expanded to include all customers with at least 1 kW of demand; and (3) whether the minimum demand thresholds for Rates 532 and 533 should be lowered to 2 MW.

1. Reasonableness of the Settlement Agreement. In opposition to approval of the Settlement Agreement, Michigan City raised several concerns with NIPSCO's rates and services that it alleges were inadequately addressed in the Settlement Agreement, including affordability, NIPSCO's commercial customer satisfaction rankings by J.D. Power, the competitiveness of NIPSCO's rates for economic development purposes, and the sufficiency of the provision for low-income assistance. Michigan City is predominantly of the view that the 9.80% ROE in the Settlement is too high. Based on the evidence presented as discussed further below, we are not persuaded by Michigan City's arguments to reject or modify the Settlement Agreement, which the Settling Parties have sufficiently shown provides a reasonable resolution of the differing positions and disputed issues presented in this complex proceeding.

Michigan City takes issue with the 9.80% ROE agreed to by the Settling Parties, especially because of NIPSCO's customer service ratings. However, the record reflects that this compromise 9.80% ROE is within the range of evidence presented, contemplates the level of business risk to NIPSCO resulting from the terms of the Settlement, and is similar to the ROE that the Commission approved for NIPSCO in its 45159 Order. Mayor Parry's concerns regarding NIPSCO's customer service were not unlike those of the RV Group, who is a party to the Settlement Agreement. In addition, despite attempts by counsel for Michigan City at the hearing to elicit testimony about the Commission's Order in Cause No. 43526, we find that the customer service, reliability, and operational and other management issues supported by the evidence in that cause are not present here. As Ms. Whitehead explained, NIPSCO has made improvements in overall customer satisfaction but is also aware that improvements can be made for its business customers and identified efforts that NIPSCO is making to continue to address customer satisfaction and improve customer service. She further testified that these issues were considered by the Settling Parties in reaching agreement on the 9.80% ROE.

Additionally, in support of the Settlement Agreement, Ms. Whitehead explained that it represents more than a $100 Million decrease from NIPSCO's as-filed revenue requirement. This is in addition to certain mitigation steps that NIPSCO identified it had taken in its case-in-chief, including its proposed change in depreciation methodology. As she further testified, in total, these reductions in expense result in a large decrease in cash flow available to NIPSCO, thereby increasing NIPSCO's need to finance expenses and capital investments. The Settlement Agreement reflects NIPSCO's agreement to these various terms, which, from NIPSCO's point of view, link directly to the ultimate agreement on ROE. NIPSCO, its customers, and the Commission

all have an interest in ensuring NIPSCO's financial health, because failure to do so will increase NIPSCO's financing costs, causing an adverse impact on the ability to attract capital investment and on customer rates.

Further, as discussed above, the OUCC and other Settling Parties provided testimony supporting the agreed-upon ROE as reasonable and in the interest of ratepayers as part of the entire settlement package. OUCC Witness Eckert specifically addressed the Settlement Agreement's benefits to affordability through its various reductions in NIPSCO's requested revenue increase. While the agreed ROE of 9.80% is higher than the lowest recommended ROE, it is still within the range of reasonable outcomes presented by the parties and benefits ratepayers by reducing the return on rate base reflected in customers' rates as compared to NIPSCO's case-in-chief proposal.

In Cause No. 45159, the Commission reduced the ROE from the level contained in the Revenue Settlement "in light of the reduced business risk to NIPSCO as a result of the approval of the Rate 831 Settlement." 45195 Order at 162. The circumstances here are markedly different from those in NIPSCO's last rate case. In the 45159 Order, we lowered the parties' stipulated ROE based on the sequencing of two separate settlement agreements—the first one addressing the revenue requirement and the second addressing the approval of the new Rate 831 industrial service structure. After the Revenue Settlement that contained the stipulated ROE was executed, NIPSCO entered into the Rate 831 Settlement and Implementation Agreement with some, but not all, of the parties to the Revenue Settlement. As such, the Revenue Settlement was entered without knowledge of how the Rate 831 proposal would be addressed or resolved. We therefore concluded that the approval of the subsequent Rate 831 Settlement and Implementation Agreement lowered NIPSCO's business risk from what had been assumed by the parties when they stipulated to an ROE in the Revenue Settlement. We explained:

> In considering the Revenue Settling Parties' recommended ROE, we note that the Revenue Settlement was finalized, signed, and filed prior to the Rate 831 Settlement and Implementation Agreement. As such, the fate of NIPSCO's proposed Rate 831 large industrial service structure was still uncertain at that time. Furthermore, at no place in the Revenue Settlement is its approval made explicitly contingent upon approval of Rate 831. The Commission's approval of the Rate 831 Settlement and Implementation Agreement and the new industrial service construct designed in it significantly mitigates the risk of the loss of industrial load to NIPSCO and the associated earnings volatility. Therefore, based on this reduced risk for NIPSCO's shareholders, we find that a decrease in NIPSCO's ROE is warranted.

45159 Order at 162. This is not the situation with which are presented in this case.

To begin with, the ARP implementing NIPSCO's Rate 831 industrial service structure was approved in Cause No. 45159 as part of a settlement that was distinct from the agreement on the revenue requirement. Here, the modifications sought to NIPSCO's ARP were contained in the Rate 831/531 Modification Settlement that was filed with NIPSCO's case-in-chief. Thus, in the Settlement Agreement pending before the Commission in this case, the Settling Parties were aware of the provisions of Rate 831/531 Modification Settlement as they presented their responsive cases and then negotiated the revenue requirement and other issues. Moreover, all the Settling Parties

either agreed that the Rate 831/531 Modification Settlement should be approved or agreed not to oppose it. As such, the Settling Parties had the opportunity to fully consider the effect of the Rate 831/531 Modification Settlement on this case and were able to take that agreement's impacts, including NIPSCO's resulting business risk, into consideration, when they agreed to an ROE of 9.80%.

Also, in Cause No. 45159, we indicated that the Rate 831 Settlement and Implementation Agreement "explicitly assigns a revenue requirement to the Rate 831 customers." 45159 Order at 162. We therefore reduced the stipulated ROE to limit the impact on non-Rate 831 customers. In the current case, the Settlement Agreement contains specific language to ensure that all customer classes receive some benefit associated with the reduced revenue requirement, limiting the benefit to Rate 531 to a cost of service-based reduction that reflects the class's production-related demand allocation. Moreover, while the introduction of Rate 831 was an innovation on NIPSCO's then existing interruptible power rider, the proposed changes to the ARP in this case maintain the overall existing structure of Rate 831 and reflect only limited changes to the rate structure. The Rate 831/531 Modification Settlement contains only a modest reduction to both the allocation of production-related demand costs to the class and in intra-class Tier 1 firm contract demand.

As discussed above, the proposed modifications to NIPSCO's ARP are consistent with the overall purpose of Rate 831, which is to retain NIPSCO's at-risk large industrial load and continue those customers' contributions to the cost of legacy production assets during NIPSCO's ongoing generation portfolio transition. Any reduction in the allocation of costs to Rate 831/Rate 531 was to be expected as the legacy costs continue to decline through retirements and increased depreciation of the legacy assets. Any intra-class reduction in Tier 1 firm contract demand was likewise expected as participating customers reduce their Tier 1 commitments in reaction to decreasing allocation of production-related costs to the class. Again, the Settling Parties in this case were afforded an opportunity to consider the impact of the Rate 831/531 Modification Settlement, including the reduction in production-related demand to the class, during settlement negotiations.

Accordingly, the Commission finds that when the Settlement Agreement is considered in its entirety, the agreed upon ROE balances the consumer parties' interests and concerns, including those expressed by Michigan City, with NIPSCO's interest in preserving its financial integrity. We therefore find the stipulated ROE of 9.80% is reasonable.

2. Rates 831/531. MIUG's objections to the Settlement Agreement relate predominantly to the fact that it does not incorporate MIUG's proposal to greatly expand eligibility for Rate 531 on materially revised tariff terms. NIPSCO did not propose any change to the eligibility criteria for Rate 531 and made clear that it did not support the material changes to its ARP being advocated by MIUG. NIPSCO argues that MIUG's proposed restructuring of Rate 531 is inconsistent with the purpose underlying the ARP and does not provide sufficient justification for the Commission to deny approval of the Settlement.

In addition to arguing that Rate 531 is unbundled transmission service and therefore invalid, MIUG also asked for Rate 531 to be expanded to all customers taking at least 1kW of service to allow significantly more customers to participate. MIUG also claimed that Rate 531 allows NIPSCO's retail customers taking service under that rate to access the wholesale market.

First, because Rate 531 maintains the Rate 831 service structure and operating mechanics, we reiterate our findings from the 45159 Order that Rate 831 is a rate for retail service. In that Order we specifically found that, "NIPSCO's proposal requires its largest industrial customers to remain as its retail customers, while at the same time providing more market choices." 45159 Order at 153. Nothing has been presented to change this finding or alter the same conclusion. NIPSCO offered additional evidence confirming Rate 831 as implemented is and remains retail service. As explained by Mr. Campbell, Rate 831 customers are purchasing transmission service at retail and the fact that it is part-and-parcel of the delivery of energy under Rate 831 means it remains a retail transaction, over which FERC would not assert jurisdiction. Also, NIPSCO is at all times the Market Participant in MISO, procuring energy and providing transmission of that energy to the customers. FERC Order No. 888 addressed when its jurisdiction applies to bundled versus unbundled service, stating: "[W]e believe that when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the [Federal Power Act] the [Federal Energy Regulatory] Commission's jurisdiction over sales of electric energy extends only to wholesale sales." Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21540, 21625, 1996 WL 239663 (May 10, 1996). *See also* Pet. Ex. 11-R at 6-8.

NIPSCO's tariff is clear that Rate 531 customers taking transmission service must also take service for energy. There is no opportunity for a customer to take transmission-only service from NIPSCO. MIUG's arguments are, therefore, unfounded.

MIUG also proposed to expand Rate 531 to all customers taking at least 1 kW of service. We note that customer contract demand under Rate 831, and proposed for Rate 531, reflect voluntary commitments by each of the large industrial participants in that class. That is a crucial aspect of both the current rate structure and the slightly modified version proposed in the Rate 831/531 Modification Settlement. MIUG, however, proposes to assign Tier 1 demand levels to rate participants based on ratable contributions to peak load. We consider that proposed approach to be fundamentally at odds with the basis for which NIPSCO's ARP was approved.

In the 45159 Order, when we approved the ARP establishing Rate 831, we emphasized that "it was appropriate and reasonably necessary for NIPSCO to revise its industrial rate structure in order to mitigate the credible and preventable threat of large industrial load loss. The record also demonstrates that it is important to NIPSCO and all of its customers to retain the Rate 831 customers and for them to continue contributing to NIPSCO's fixed production costs." 45159 Order at 157. The NIPSCO system is uniquely situated in that NIPSCO's five largest customers account for 40% of total system load, and NIPSCO was facing serious risk of continuing losses of large industrial load. *Id.* at 151. The Commission recognized that, by stabilizing large industrial load with 5-year contracts, Rate 831 would facilitate a more orderly transition as NIPSCO retires aging coal plants and procures replacement capacity. *Id.* at 155-56. The key terms and conditions of Rate 531 remain materially the same as what we approved in the 45159 Order, and MIUG has not suggested otherwise. Instead, MIUG seeks to relitigate the ARP approval for Rate 831 but has not shown that the previously approved service structure of Rate 831, and specifically its eligibility terms, require material revision over the objection of NIPSCO.

In addition, we find that the modifications sought by MIUG would be inconsistent with the purpose underlying the original ARP approval and the Commission's public interest determinations. In approving the Rate 831 ARP, we found that:

> NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers while addressing its aging generation and navigating a dynamic economic environment. Although the Rate 831 proposal requires NIPSCO's other customer classes to pay higher rates in the near term than they are currently paying today under the existing service structure, the long-term risk is that these large industrial customers will otherwise exercise their options to significantly shift load off NIPSCO's system. When that occurs, costs might reasonably be reallocated to the remaining customer classes. While the OUCC and CAC focused on the fairness of a cost shift within this rate case between Rate 831 and other classes, the record shows that denying Rate 831 now would likely result in even higher costs, which would otherwise have been collected under Rate 831 if these customers further bypass NIPSCO's service. When considering the full range of impacts in play rather than just the near-term cost shift, Rate 831 is a reasonable solution now rather than later. We find that retaining the current service structure would only increase the risk that these customers will exercise their options to self-generate additional power or relocate production to avoid an increasing NIPSCO electric price.
>
> Given that large industrial customers constitute such a significant portion of NIPSCO's retail electric sales, reducing their load would cause precipitous declines in NIPSCO's revenues and operating margins far faster than could be offset by growth in other sectors. In the long run, we find that such load loss would subject remaining customers and customer classes to increased costs above and beyond the near term costs of the Rate 831 Settlement. Conversely, we find that approval of this new service structure will provide Rate 831 customers increased flexibility to meet their electricity requirements and improve their ability to compete in global markets while other customers and the utility benefit from reduced risks and greater certainty in large industrial load for a set period of time.

45159 Order at 154-55.

No evidence was presented of any material change in circumstances that would alter the findings underlying the approved ARP. Utility rates are routinely applied through distinct schedules for defined rate classes. *See* Ind. Code § 8-1-2-46. NIPSCO's large industrial rates, including those previously applicable to current Rate 831 customers, have long included demand thresholds of 10 MW or more. Based on the evidence presented, the Commission finds that MIUG has not shown that its proposal to expand Rate 531 eligibility to most of NIPSCO's commercial and industrial customers with lower demands would be reasonable, consistent with the public interest, or supported by the statutory criteria for ARP approvals under Ind. Code § 8-1-2.5-5(b).

3. Rates 532 and 533. MIUG also seeks to reduce the minimum demand thresholds for Rates 532 and 533 to 2 MW and to eliminate the requirement that the customer own the equipment necessary to reduce transmission voltage to the individual customer's voltage requirements. MIUG argues that, otherwise, customers served directly from the

transmission system would pay costs of the distribution system under NIPSCO's Rate 526. However, as NIPSCO Witness Taylor explained, MIUG's underlying premise is incorrect because Rate 526 is structured so that transportation customers on Rate 526 pay a discounted rate such that costs of the distribution system are excluded from their rates. As to the equipment ownership requirement, we agree with Mr. Campbell that if NIPSCO must own the equipment that is necessary to transform the voltage from transmission voltage to distribution voltage, then that customer is not truly a transmission customer. Accordingly, we find the evidence does not support the existence of an unfair burden or discriminatory barrier in requiring customers on Rates 532 and 533 to maintain their own transmission equipment should they require voltage reduction to meet their own needs.

Additionally, the Settlement contains a term that NIPSCO will study the operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to the rate or the creation of another rate is appropriate. This review will include, but not be limited to, a review of the appropriate minimum demand level for participation, as well as demand blocks and demand and energy charges. Jt. Ex. 1, Para. B.7.(k). We find this adequately addresses any remaining concerns over Rates 532 and 533.

B. Ultimate Findings on Settlement Agreement and Rate 831/531 Modification Settlement. Based on the evidence presented, we find that the Settlement Agreement and the Rate 831/531 Modification Settlement should be approved without modification.

With regard to the Rate 831/531 Modification Settlement, NIPSCO has requested minor modifications to its existing ARP that was originally approved in Cause No. 45159. Ind. Code § 8-1-2.5-6(a)(1) authorizes the Commission to adopt alternative regulatory practices, procedures and mechanisms that are in the public interest and that enhance or maintain the value of NIPSCO's retail energy services or property. Our consideration of the public interest is to be guided by our review of the factors set forth in Ind. Code § 8-1-2.5-5. Specifically, Ind. Code § 8-1-2.5-5(b) states in pertinent part:

> (b) In determining whether the public interest will be served, the commission shall consider the following:
>
> > (1) Whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful.
> >
> > (2) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state.
> >
> > (3) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency.

> (4) Whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

NIPSCO's proposal, adopted by the Settling Parties, substantially retains the structure and terms of existing Rate 831, with modest modifications to support the Rate 531 contract renewals and address future load adjustments to facilitate effective capacity planning. The same statutory considerations remain applicable to the requested modifications. Based on the evidence presented, we find our conclusions in the 45159 Order on these factors remain applicable, and there has been no basis shown to revisit the Commission's prior determinations.

With respect to the first factor, the Commission found in Cause No. 45159 that NIPSCO's large industrial customers utilize energy intensive processes; those customers have alternatives to substantially reduce or eliminate load from NIPSCO's system through self-generation, production shifts or plant closures; NIPSCO had experienced substantial losses of large industrial load; and Rate 831 addressed those risks with a more competitive rate offering that retained those customers as retail customers while stabilizing large industrial load during a crucial period for capacity planning. 45159 Order at 153. The record confirms the same conditions continue to exist and support the modifications sought in this case.

Regarding the second factor, the Commission previously found in Cause No. 45159 that the ARP establishing Rate 831 will be beneficial to NIPSCO and all its customers because it effectively addressed the serious risk of continued erosion in large industrial load, thereby preventing greater and unmanaged reductions. 45159 Order at 154-55. The Commission concluded that the new service structure would "provide Rate 831 customers increased flexibility to meet their electricity requirements and improve their ability to compete in global markets while other customers and the utility benefit from reduced risks and greater certainty in large industrial load for a set period of time." *Id.* at 155. The record confirms there is still serious risk of precipitous loss in industrial load, which is appropriately addressed with the modifications at issue, in particular the Rate 531 contract renewals and the agreed process for future load reductions.

In Cause No. 45159, the Commission further found the ARP satisfied the third factor by promoting utility efficiency, particularly facilitating effective capacity planning during the key transition period for NIPSCO's generation resources. *Id.* at 155. The Commission concluded that "Rate 831 reduces the amount of replacement capacity NIPSCO must plan for, provides more reliable load projections for planning purposes, and mitigates the risk of building excess capacity." *Id.* Those considerations remain important, as NIPSCO has implemented the first steps in its resource transition but is continuing to navigate future retirements and replacement capacity. The ARP modifications in this case will provide additional support for capacity planning and utility efficiency, by establishing a clear "glide path" for future Rate 531 load adjustments during the period that legacy coal asset costs are being recovered in base rates.

Finally, the Commission found in Cause No. 45159 that the Rate 831 ARP satisfied the fourth statutory factor, insofar as traditional ratemaking impeded NIPSCO's ability to provide competitive rates for large industrial customers with demonstrated capability to exercise alternatives including self-supply, production shifts, and facility closures. *Id.* at 155-156. The

record here confirms the same conditions have continued, and the proposed modifications to the ARP support the function of Rate 531 to retain the class as retail load.

With respect to each of the statutory factors, the Commission finds no reason to depart from the findings in Cause No. 45159, and further finds the modifications proposed by NIPSCO will assist in supporting the purposes of the ARP as identified in Cause No. 45159. The modification to the ARP sought through the Rate 831/531 Modification Settlement resolves uncertainties that could bear negatively on other customers if the agreements with the Rate 831 customers were simply allowed to expire by their terms upon approval of new base rates. The Rate 831/531 Modification Settlement is in the public interest, especially when coupled with the additional guidance provided in the Settlement Agreement. Accordingly, we find the modification to NIPSCO's existing ARP should be approved.

The revenue allocation shall be as set forth in the Settlement Agreement and Petitioner's Exhibit 19-S, Attachment 19-S-A. This revenue allocation is based upon the projected rate base and capital structure; the actual revenue allocation shall be based upon the actual rate base, and capital structure at the time, following the three-step mitigation process set forth in the Settlement Agreement. We find that based upon the projected capital structure and rate base, the rates set forth in Attachment 19-S-B and the tracker allocations set forth in Attachment 19-S-D of Petitioner's Exhibit 19-S, are appropriate and should be approved.

We further find that the depreciation accrual rates set forth in Attachment B hereto should be approved. We also find that the regulatory accounting for cost of removal for NIPSCO's coal-fired generation-related assets described in Petitioner's Exhibit 3 at pages 117-19 should be approved.

The proposed ECT, using the filing methodology and frequency described by NIPSCO Witness Blissmer and summarized herein, should likewise be approved. The costs to be recovered through the ECT are NOx emissions allowances and variable chemical costs, allocated among the classes as set forth in the Settlement Agreement.

As noted, Section B.14. of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement will be adopted as proposed by NIPSCO's case-in-chief, as modified in its rebuttal testimony. This includes all the relief summarized in Paragraph 5 of this Order, which has not otherwise been modified by the Settlement. The Commission finds Section B.14. of the Settlement Agreement to be reasonable and it is approved with the entirety of the Settlement Agreement.

We therefore find that NIPSCO should be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $261,923,892, total base rate revenue of $1,767,260,404, and total net operating income of $402,900,940. This is based upon a projected test year ending net original cost rate base of $5,925,013,822 as follows:

Net Utility Plant	$ 4,321,816,455
RMS Unit 14/15 Retirement	$ 593,022,393
Joint Venture Reg Assets	$ 817,299,925
Reg Assets - Cause 44688 & 45159	$ 23,510,338
Electric 2021-2026 TDSIC Plan Cause #45557	$ 24,558,486
FMCA - Post 45159 & CCR Remediation	$ 545,389
Materials & Supplies	$ 98,989,010
Production Fuel	$ 45,271,825
	$ 5,925,013,822

We further find that a fair return should be authorized based upon this net original cost rate base and a projected weighted average cost of capital of 6.80%, as follows:

	Dollars	Cost %	Weighted Average Cost of Capital %
Common Equity	$4,564,821,051	9.80%	5.06%
Long-Term Debt	$3,233,952,976	4.66%	1.70%
Customer Deposits	$59,541,950	5.63%	0.04%
Deferred Income Taxes	$1,393,665,855	0.00%	0.00%
Post-Retirement Liability	$13,945,116	0.00%	0.00%
Prepaid Pension Asset	$(424,946,780)	0.00%	0.00%
Post-1970 ITC	$640,278	7.67%	0.00%
Totals	**$8,841,620,445**		**6.80%**

The rate increase authorized herein should be implemented in multiple steps as set forth below:

(a) Step 1 Rates Subject to Refund: Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023 and calculate the Step 1 rates using those certified figures.[18] NIPSCO will provide all parties to this proceeding with its certification. The parties will have 60 days to verify or state any objection to the net plant in service numbers from those that NIPSCO certifies. All parties to this proceeding shall be permitted to conduct discovery to verify relevant

[18] For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of June 30, 2023.

construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on or about March 1, 2024 and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023 and calculate the Step 2 rates using those certified figures.[19] NIPSCO will provide all parties to this proceeding with its certification. The parties will have 60 days to verify or state any objection to the net plant in service numbers from those that NIPSCO certifies. The parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) Additional Interim Phases: In the event either Dunn's Bridge I or Indiana Crossroads Solar are not fully in service by June 30, 2023 (meaning the portion that is not certified as partially in service as described in Mr. Campbell's rebuttal testimony) but come into service on or before December 31, 2023, then an additional interim step will be implemented after Step 1 and before Step 2. This additional step compliance filing will be based on the addition to rate base and amortization expense for Dunn's Bridge I or Indiana Crossroads Solar (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service. The rates will take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections.

The Commission further finds and concludes that the Settlement Agreement and the Rate 831/531 Modification Settlement are reasonable, supported by substantial evidence, and in the public interest. Accordingly, both the Settlement Agreement and Rate 831/531 Modification Settlement are approved.

11. Effect of Settlement Agreement. The parties agree that the Settlement Agreements are not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce their terms; consequently, with regard to future citation of the Settlement Agreements or of this Order, the Commission finds our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC March 19, 1997).

12. Confidentiality. NIPSCO filed motions for protection and nondisclosure of confidential and proprietary information on October 7, 2022, February 10, 2023, and February 16, 2023. The Industrial Group filed a motion for protection and nondisclosure of confidential and

[19] For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2023.

proprietary information on January 20, 2023. Each motion was supported by affidavits showing certain documents to be submitted to the Commission contain confidential trade secrets as defined under Ind. Code § 23-2-3-2. Docket Entries were issued on each of these motions finding such information to be entitled to confidential treatment on a preliminarily basis, after which the information was submitted under seal. The Commission finds all such information granted preliminary confidential treatment is confidential under Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement and the Rate 831/531 Modification Settlement, copies of which are attached to this Order, are approved.

2. The modification to Petitioner's ARP approved in Cause No. 45159 as set forth in the Rate 831/531 Modification Settlement and Settlement Agreement is approved.

3. Petitioner is authorized to increase its rates and charges for electric utility service in multiple steps as described in Finding Paragraph 10.

4. New depreciation rates applicable to NIPSCO's common and electric plant are approved as explained in, and attached to, this Order.

5. Petitioner shall file under this Cause for approval by the Commission's Energy Division the new schedules of rates and charges along with its revised tariff consistent with the Settlement Agreement and the rates and charges approved in this Order.

6. Petitioner shall certify its net plant, original cost rate base, and capital structure at June 30, 2023 (Step I) and December 31, 2023 (Step II) and calculate the resulting rates and charges, which shall be made effective upon filing and approval of the Commission's Energy Division in accordance with the findings herein, subject to being contested and trued-up consistent with the Settlement Agreement.

7. To the extent that either Crossroads Solar or Dunn's Bridge I Solar is not completely in service as of June 30, 2023 but is in service before December 31, 2023, Petitioner is authorized to implement an additional interim phase to its increase, based upon the Phase I capital structure as described in Finding Paragraph 10.B.

8. Petitioner is authorized to file updated factors for its rate adjustment mechanisms in accordance with this Order, and such changes shall be effective simultaneously with approval of NIPSCO's new basic rates.

9. Petitioner is granted deferred accounting authority as described in Finding Paragraph 10.B. This includes, but is not necessarily limited to, deferred accounting for cost of removal at coal-fired generating units following the retirement of the last such unit, for discounts provided for purposes of the Economic Development Rider, and for actual costs incurred for environmental and NOx prior to recovery through the new ECT.

10. Petitioner's proposed form of Electric Service Tariff is approved, consistent with the Settlement Agreement and the Rate 831/531 Modification Settlement and this Order, inclusive of the associated General Rules and Regulations and Standard Contracts.

11. Petitioner is directed to file under this Cause all information required by the Settlement Agreement.

12. The information filed in this Cause pursuant to motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

13. This Order shall be effective on and after the date of its approval.

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED: AUG 02 2023

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61, AND, 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF A NEW RIDER FOR VARIABLE NON-LABOR O&M EXPENSES ASSOCIATED WITH COAL-FIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POST-RETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.	CAUSE NO. 45772

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 10th day of March, 2023, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); NIPSCO Industrial Group ("Industrial Group");[1] NLMK Indiana; United States Steel Corporation;[2] Walmart Inc.; RV Industry User's Group ("RV Group");[3] and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"). The Setting Parties, solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth below represent a fair and reasonable resolution of the issues in this Cause subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein. The Settling Parties agree that this Agreement resolves all disputes, claims and issues arising from the electric general rate case proceeding currently pending in Cause No. 45772 as among the Settling Parties, including revenue requirement, cost of service, rate design, and cost allocation

---

1 The Industrial Group is comprised of Accurate Castings and Kingsbury Castings, BP Products North America, Inc., Cargill, Cleveland Cliffs Steel LLC, Enbridge, Linde, Marathon, and USG Corporation.

2 United States Steel Corporation's signature page will be late-filed upon receipt of authorization from its executive management.

3 The RV Industry User's Group is comprised of LCI Industries, Inc.; Patrick Industries, Inc.; Forest River, Inc.; and Keystone RV Company.

issues. The Settling Parties agree that NIPSCO's requested relief in this Cause should be granted except as expressly modified herein.

A. Background

1. NIPSCO's Current Basic Rates and Charges. NIPSCO's current electric basic rates and charges were approved in the Commission's December 4, 2019 Order in Cause No. 45159 (the "45159 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement on Less Than all the Issues resolving revenue requirement and other miscellaneous issues ("45159 Revenue Settlement") between NIPSCO and the majority of the intervenors.[4] The Commission also approved a Stipulation and Settlement Agreement on Rate 831 Implementation (the "Rate 831 Settlement").[5] Those new basic rates and charges went into effect on January 2, 2020 (the first billing cycle for January 2020). The 45159 Order approved, among other items, an increase in NIPSCO's basic rates and charges. The 45159 Order also approved an alternative regulatory plan which implemented a new service structure for certain industrial customer through NIPSCO's new Rate 831.

---

[4] The 45159 Revenue Settlement was entered into on April 25, 2019, by and between NIPSCO, NIPSCO Industrial Group ("Industrial Group"), NLMK Indiana ("NLMK"), United States Steel Corporation ("US Steel"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Walmart Inc., Northern Indiana Commuter Transportation District, Sierra Club, and the Indiana Office of Utility Consumer Counselor ("OUCC") (collectively the "Revenue Settling Parties"). On May 15, 2019, Indiana Municipal Utility Group joined the 45159 Revenue Settlement.

[5] The Rate 831 Settlement was entered into on May 17, 2019, by and between NIPSCO, Industrial Group, NLMK Indiana, and US Steel.

2. NIPSCO's Current Depreciation Accrual Rates: NIPSCO's current common and electric depreciation rates were approved in the Commission's 45159 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings: NIPSCO files a quarterly Fuel Adjustment Clause ("FAC") proceeding in accordance with Ind. Code § 8-1-2-42(d) in Cause No. 38706-FAC- XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs. Historically, NIPSCO has agreed that the OUCC and other interested parties should have thirty-five (35) days to review NIPSCO's FAC filings and NIPSCO has agreed to continue that practice.

4. NIPSCO's Tracking Mechanisms: In coordination with its FAC proceedings, NIPSCO files semi- annual proceedings in: (a) Cause No. 44156-RTO-XX to recover costs associated with MISO non-fuel costs and revenues and to provide for off-system sales sharing through its Rider 871 – Adjustment of Charges for Regional Transmission Organization and Appendix C – Regional Transmission Organization Adjustment Factor ("RTO Tracker") approved by the Commission in its 45159 Rate Case Order,[6] and (b) Cause No. 44155-RA-XX to recover prudently incurred capacity costs

[6] In its August 25, 2010, Order in Cause No. 43526, the Commission found that NIPSCO's MISO non-fuel costs and revenues and off system sales sharing should be included in one mechanism designated as the RTO Adjustment. In its December 21, 2011, Order in Cause No. 43969, the Commission approved the implementation of the RTO Adjustment approved in Cause No. 43526 by approving Rider 671 and Appendix C. In its July 18, 2016, Order in Cause No. 44688, the Commission approved NIPSCO's request for authority to defer, as a regulatory asset or liability, an amount equal to 50% of annual off system sales margins above or below the level of off-system sales margins included in

through its Rider 874 – Adjustment of Charges for Resource Adequacy and Appendix F – Resource Adequacy Adjustment Factor ("RA Tracker") approved by the Commission in its 45159 Rate Case Order.[7]

NIPSCO files an annual proceeding in Cause No. 43618-DSM-XX to recover program costs, lost revenues, and financial incentives associated with approved demand side management and energy efficiency programs through its Rider 883 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) and Appendix G - Demand Side Management Adjustment Mechanism (DSMA) Factor.[8]

---

the test year for recovery through the RTO tracker. In its 45159 Rate Case Order, the Commission approved NIPSCO's request to: (1) remove MISO charges and credits and collect 100% of MISO charges that are not included in the FAC through the RTO; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO; (3) remove all back-up and maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology. In its April 27, 2022 Order in Cause No. 44156-RTO-21, the Commission approved, among other things, a modification of Rider 871 – Adjustment of Charges for Regional Transmission Organization to include recovery of net non-fuel PJM Interconnect LLC costs and revenues.

[7] In its August 25, 2010 Order in Cause No. 43526, the Commission found that NIPSCO's prudently incurred capacity should be recovered through the Resource Adequacy or RA Adjustment. In its December 21, 2011 Order in Cause No. 43969, the Commission approved the implementation of the RA Adjustment approved in Cause No. 43526 by approving Rider 674 and Appendix F. The 45159 Rate Case Order approved, among other items, the removal of all embedded capacity costs and/or credits from base rates; tracking of 100% of all capacity costs and/or credits as a charge/credit to customers through the RA Adjustment; and demand allocators for the RA Adjustment.

[8] The initial tracking mechanism was approved in the Commission's May 25, 2011 Order in Cause No. 43618. In its February 27, 2017 Order in Cause No. 43618-DSM-11, the Commission approved a modification to NIPSCO's Rider 783 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) to move from a semi-annual timeline to an annual filing. In its 45159 Rate Case Order, the Commission approved Rider 883 – Demand Side Management Adjustment Mechanism and Appendix G – DSMA Factor, to become effective January 1, 2020.

NIPSCO files an annual proceeding in Cause No. 44198-GPR-XX to revise the Green Power Rider rate set forth in its Rider 886 – Green Power Rider and Appendix H – Green Power Rider Rate.[9]

NIPSCO has a semi-annual tracking mechanism to recover federally mandated costs through its Rider 787 – Adjustment of Charges for Federally Mandated Costs and Appendix I – Federally Mandated Cost Adjustment Factor.[10] NIPSCO has requests for a Certificate of Public Convenience and Necessity for federally mandated projects pending in Cause Nos. 45700 and 45797 for recovery through NIPSCO's FMCA tracking mechanism.

NIPSCO files a semi-annual proceeding in Cause No. 45557-TDSIC- XX to recover 80% of eligible and approved capital expenditures and transmission, distribution, and storage system improvement charge ("TDSIC") costs through Rider 888 - Adjustment of Charges for Transmission, Distribution and Storage System

---

[9] The initial tracking mechanism was approved in the Commission's December 19, 2012 Order in Cause No. 44198. In its December 28, 2016 Order in Cause No. 44198-GPR-8, the Commission approved a modification to NIPSCO's Rider 786 – Green Power Rider to move from a semi-annual timeline to an annual filing. In its June 24, 2020 Order in Cause No. 44198 GPR 12, the Commission approved modifying the GPR to separate NIPSCO's recovery of certification costs from marketing costs.

[10] The initial tracking mechanism was approved in the Commission's January 29, 2014 Order in Cause No. 44340. Although NIPSCO has two pending requests to utilize the FMCA tracking mechanism, NIPSCO does not currently recover any costs through the FMCA tracking mechanism.

Improvement Charge and Appendix J - Transmission, Distribution and Storage System Improvement Charge.[11]

5. This Proceeding: On September 19, 2022, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to modify its retail rates and charges for electric utility service through a phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders (both existing and new); (3) approval of a new rider for variable non-labor O&M expenses associated with coal-fired generation ("Variable Cost Tracker"); (4) modification of the fuel cost adjustment to pass back 100% of off-system sales revenues net of expenses; (5) approving revised common and electric depreciation rates applicable to its electric plant in service; (6) approving necessary and appropriate accounting relief, including but not limited to approval of (a) certain deferral mechanisms for pension and other post-retirement benefits ("OPEB") expenses, (b) regulatory accounting for actual costs of removal associated with coal units following the retirement of the last coal unit (Michigan City Generating Station ("Michigan City") Unit 12), and (c) a modification of Joint Venture accounting authority to consolidate the reserves for purposes of passing back Joint Venture cash; (7) approving alternative regulatory plans for the (a) modification of NIPSCO's industrial rate service structure, and (b) implementation of a new low income program; (8) reviewing and determining

[11] The initial tracking mechanism was approved in the Commission's February 17, 2014 Order in Cause No. 44371.

the correct amount to include in NIPSCO's "earnings bank" for purposes of Ind. Code § 8-1-2-42.3; (9) authorizing NIPSCO to implement temporary rates; and (10) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on September 19, 2022. On January 20, 2023, the OUCC and intervenors filed their respective cases-in-chief and on February 16, 2023, NIPSCO filed its rebuttal testimony and exhibits and several intervenors filed cross-answering testimony and exhibits.

As discussed within NIPSCO's Verified Petition, and the testimony of various parties including NIPSCO, since the 45159 Rate Case Order, there are a few compounding drivers causing NIPSCO to request a change in rates at this time. NIPSCO is in the midst of substantial generation transition, whereby its generation fleet will be converted from one dominated by coal-fired steam generation to a modern fleet consisting predominantly of renewables, storage and natural gas. By the close of the test year, NIPSCO will have placed in service substantial investments in new utility plant, including several new renewable generating assets. NIPSCO has experienced delays, which are driven by factors outside of NIPSCO's control, in bringing all of its Commission-approved renewable energy projects online. This in turn has caused NIPSCO to continue operations of R.M. Schahfer Generating Station ("Schahfer") Units 17 and 18 longer than anticipated. The delays associated with these renewable energy projects have also required NIPSCO to take additional actions to ensure it continues to

provide safe, reliable, and adequate service to its customers. Rates need to be changed to properly reflect the effects of these drivers as soon as possible.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income:

(a) Revenue Requirement: As explained further herein, the Settling Parties agree to withdraw NIPSCO's proposed Variable Cost Tracker ("VCT") and instead agree to establish a new Environmental Cost Tracker ("ECT"). The ECT will recover fewer categories of costs than the proposed VCT, and the forecasted annual costs to be recovered through the ECT are $29,880,196. The costs NIPSCO initially proposed to recover through the VCT are now being excluded from the ECT and will instead be recovered through base rates. The Settling Parties agree that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount originally requested by NIPSCO in its case-in-chief. The Settling Parties agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below. Joint Exhibit A attached hereto represents the schedules supporting the calculation of the agreed upon revenue requirement based on the 12-month period ending December 31, 2023.

(b) Net Operating Income: The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.1(a) above results in a proposed authorized net operating income ("NOI") of $402,900,940.

2. Original Cost Rate Base, Capital Structure, and Fair Return:

(a) Original Cost Rate Base: The Settling Parties agree that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based upon this Agreement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.80%, yielding an overall return for earnings test purposes of $402,900,940, based upon:

(i) An original cost rate base of $5,925,013,822, inclusive of materials, supplies, production fuel, and regulatory assets. This amount reflects that forecasted additions to Renewable Energy Joint Venture Investments will be reduced to reflect the additional Investment Tax Credit NIPSCO will receive for Dunn's Bridge I, as reflected in NIPSCO's rebuttal alternative revenue requirement filed position. NIPSCO's current *estimate* is a reduction in additions to forecasted Joint Venture Regulatory Assets of $23,700,000 (for Step 1) and $23,693,692 (net of amortization for Step 2), and the annual amortization expense in the amount of $798,660.

However, the *actual* reductions will be based on final project cost, which could be slightly more or less.

(ii) NIPSCO's forecasted capital structure; and

(iii) An authorized return on equity ("ROE") of 9.80%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.80% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	Dollars	Cost %	WACC %
Common Equity	$4,564,821,051	9.80%	5.06%
Long-Term Debt	$3,233,952,976	4.66%%	1.70%
Customer Deposits	$59,541,950	5.63%	0.04%
Deferred Income Taxes	$1,393,665,855	0.00%	0.00%
Post-Retirement Liability	$13,945,116	0.00%	0.00%
Prepaid Pension Asset	$(424,946,780)	0.00%	0.00%
Post-1970 ITC	$640,278	7.67%	0.00%
Totals	**$8,841,620,445**		**6.80%**

3. Depreciation and Amortization Expense:

(a) Depreciation Expense: The Settling Parties agree that the depreciation accrual rates recommended by NIPSCO in this proceeding should be approved with the following exceptions:

(i) The amortization period for retired coal-fired generating units and the regulatory assets resulting from regulatory accounting authorized

by the 45159 Rate Case Order shall conclude June 30, 2034. This produces a reduction of approximately $26.0 Million in depreciation expense and a reduction of an additional approximate $8.8 Million for the amortization of the regulatory asset resulting from the retirement of Schahfer Units 14 and 15.

(ii) Pro forma depreciation expense will be increased approximately $9.8 Million to reflect additional demolition costs for Schahfer and Michigan City.

(iii) NIPSCO will move to stay Cause No. 45700, and upon Commission approval of all terms of this Agreement, NIPSCO shall move to dismiss Cause No. 45700 with prejudice. NIPSCO will move to stay Cause No. 45797, including staying all post-hearing briefing, and upon Commission approval of all terms of this Agreement, NIPSCO shall move to dismiss Cause No. 45797. In the event this Agreement is not approved in its entirety and with respect to NIPSCO's recovery of costs in relation to the projects proposed in Cause No. 45797, the non-NIPSCO parties in Cause No. 45797[12] agree to not object on the basis of the timeliness of the Petition in that Cause or issuance of a Commission order in that Cause, to recovery of costs incurred by NIPSCO after June 1, 2023, in relation to the projects proposed in that Cause. In the event the Commission rejects this Agreement, NIPSCO will move to lift the stay in those

12 This includes the OUCC, NIPSCO Industrial Group, and CAC.

proceedings, and except as otherwise agreed to above with respect to Cause No. 45797, litigation will resume in both Causes, with all parties able to take any position in the Causes as may be justified by the law and the facts and that are not inconsistent with the terms of this Agreement.

(iv) Depreciation rates for non-coal-fired generation assets shall be reduced, to produce an additional $9.5 Million reduction.

(v) Depreciation rates will be calculated by NIPSCO to produce these changes and will be included in the testimony supporting this Agreement, to be filed on March 17, 2023.

(b) Amortization Expense: The Settling Parties agree that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding with the following exceptions:

(i) The Cause No. 45159 regulatory asset amortization expense will be adjusted by an $8.22 Million annual reduction.

(ii) There will be a $1.7 Million annual reduction from moving the amortization periods for COVID and Rate Case Expense regulatory asset balances from two to four years.

(iii) There will be a $3.1 Million annual reduction from moving the amortization period for FMCA and TDSIC regulatory asset balances from four to seven years.

(iv) NIPSCO will make a compliance filing at the conclusion of all amortization periods to remove the amortization from the revenue requirement, and rates will be adjusted accordingly.

(c) Future Cost of Removal and Regulatory Accounting:

(i) NIPSCO will not file federal mandate cases pursuant to Ind. Code ch. 8-1-8.4 to recover costs to satisfy any asset retirement obligations associated with coal-fired generation. Instead, NIPSCO will debit FERC Account 108 for reasonable and prudent costs incurred for removal cost associated with coal-fired generation per the FERC Uniform System of Accounts, which entry will be reflected in future depreciation studies. NIPSCO will seek to adjust its future depreciation studies to reflect reasonable and prudent retirement costs.

(ii) The Settling Parties agree regulatory accounting for cost of removal (COR) for its coal-fired generation related assets should be approved as outlined in NIPSCO Witness Shikany's direct testimony (pp. 117-119) in this Cause and agree to the creation of a regulatory liability or asset, as applicable, to be included in future base rates upon the elimination of the appropriate FERC

Plant-in-Service account, subject to any challenge permitted by law, including the reasonableness and prudence of the cost.

4. Pro Forma Net Operating Income at Present Rates:

(a) Revenues: The Settling Parties accept a portion of the proposed increase in the residential sales forecast proposed by Industrial Group, which increases revenues by approximately $2.0 Million.

(b) Labor: The Settling Parties agree NIPSCO's proposed adjustment for vacant positions will be reduced by $2.2 Million.

(c) Pension and OPEB Expense: The Settling Parties accept NIPSCO's proposed adjustment to increase Pension and OPEB Expense by a combined $15.2 Million based upon the most recent actuarial report available prior to the filing of NIPSCO's case-in-chief. NIPSCO withdraws its request for a pension/OPEB balancing account.

(d) Vegetation Management: The Settling Parties agree NIPSCO's proposed vegetation management expense will be reduced by $5.8 Million, resulting in a total annual vegetation management expense of $25.1 Million (NIPSCO's 2022 budgeted expense escalated by a 5.20% inflation factor).

(e) Fuel Costs: The Settling Parties agree the base cost of fuel proposed in NIPSCO's case-in-chief will be reduced by $25.0 Million.

(f) Schahfer Fire: The Settling Parties agree a $1.06 million annual O&M reduction will be made in this case and through June 30, 2034 to resolve all known and/or disclosed issues related to the fire at Schahfer in July of 2020. NIPSCO will propose this same O&M reduction of $1.06 million per year in future general rate cases. This term shall survive the termination of this Agreement and expire on June 30, 2034. NIPSCO represents that it is unaware of any facts that would support a claim for disallowance of any expenses or costs that could be attributable to the fire that has not already been presented to the Commission. The Settling Parties reserve all rights to pursue further adjustments should previously unknown or undisclosed facts support further disallowance.

(g) Other O&M: The Settling Parties agree a further reduction to O&M in this case shall be made, to reduce O&M by a total of $4.7 Million. This reduction addresses, among other issues, CAC's proposed disallowance of Edison Electric Institute expenses.

5. Environmental Cost Tracker: NIPSCO's proposed Variable Cost Tracker shall be renamed the Environmental Cost Tracker ("ECT") and shall be approved, using the filing methodology and frequency described by NIPSCO Witness Blissmer, except as modified herein. The only costs to be recovered through the ECT are NOx emissions allowances and variable chemical costs (estimated to be $30 Million per year). The ECT will be allocated among rate classes on the basis of energy. For Rate 526, the Settling

Parties agree to a demand-based rate design, with recovery through demand charges. NIPSCO will make good faith efforts to monetize unused NOx allowances, with 100% of benefits passed to NIPSCO customers through the ECT, to re-evaluate procurement practices, and to report on monetization in each ECT tracker filing. The costs associated with generation maintenance and outages originally proposed by NIPSCO as part of the VCT will be embedded in base rates in the amount estimated by NIPSCO in its case-in-chief of approximately $72 Million. For the costs that will be included in base rates, the Settling Parties agree that these costs will be allocated in the same manner that these costs were allocated in Cause No. 45159 to maintain the "status quo" regarding allocation, which includes both a demand- and energy-based allocation component.

6. Phased Rate Implementation:

(a) Step 1 Rates Subject to Refund: Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023 and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the

amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of June 30, 2023. NIPSCO will provide all Parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All Parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on or about March 1, 2024 and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have

been placed in service and are used and useful in providing utility service as of December 31, 2023. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) Additional Interim Phases: In the event either Dunn's Bridge I or Indiana Crossroads Solar are not fully in service by June 30, 2023 (meaning the portion that is not certified as partially in service as described in Mr. Campbell's rebuttal testimony) but come into service on or before December 31, 2023, then an additional interim step will be implemented after Step 1 and before Step 2. This additional step compliance filing will be based on the addition to rate base and amortization expense for Dunn's Bridge I or Indiana Crossroads Solar (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service. The rates would take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections.

7. Cost of Service, Rate Design and Rate 831/531 Settlement:

(a) Rate 831/531 Settlement. All Settling Parties agree to support or not oppose adoption of the Rate 831/531 Settlement. All Parties not signatories to the Rate 831/531 Settlement retain all rights in future proceedings to take any position with respect to cost of service and Rate 531 issues.

(b) Mitigation. The Settling Parties acknowledge that, as presented in NIPSCO's case-in-chief and rebuttal, residential rates under Rate 511 are being subsidized by several other rate classes, including, but not limited to, Rate 520 through Rate 533. For this reason, the Settling Parties have agreed to mitigating a portion of the subsidy in this Agreement consistent with the Commission's policy of gradualism. The reduction in annual revenue (*i.e.*, the annual revenue below NIPSCO's as-filed case) will be allocated: 1st to maintain Rate 531 at cost of service based on 180 megawatts ("MW") of allocated demand as reflected in Rate 831/531 Settlement; 2nd 25% of the remaining amount for subsidy reduction; and 3rd with the 75% remaining amount allocated on an across-the-board basis. Because Rate 831 is being brought to parity at 180 MW of allocated demand, it will not receive either a reduction to reduce subsidies (the 25% portion) or a reduction on an across-the-board basis (the 75% portion). Rate 811 rates will participate in the across-the-board reduction (the 75% portion). Rates will be designed so that no rate class that is currently being subsidized will move to subsidizing other rates, and no rate that is currently subsidizing other rate classes will

move to being subsidized by other rates. The provisions of this paragraph will be implemented in the cost of service and rates included with NIPSCO's settlement testimony, which will be submitted to the Commission by March 17, 2023.

(c) Industrial Group-Specific Issues. The Industrial Group agrees not to pursue its proposal for voltage-adjusted FAC and revised allocation for renewable resources in this case. All Settling Parties retain all rights in future proceedings to litigate these issues.

(d) Production Demand Allocation in Future Cases. In its next electric base rate case, NIPSCO will prepare a 4 coincident peak ("CP") and 12 CP cost of service analysis for purposes of allocating production-related demand costs and make each analysis available to all parties in the case. NIPSCO will determine which cost of service analysis to propose in its case-in-chief, and all other parties will have the right to take any position with regard to cost of service in that case.

(e) Increases in Load by Rate 531 Customers. The Settling Parties will discuss concerns relating to protections for other classes in the event of future increases in firm load by new or existing Rate 531 customers, including any appropriate clarifications.

(f) Future Reductions in Tier 1 Load and Cost Allocations. Future reductions to Tier 1 load and cost allocations to Rate 531 as contemplated in the Rate

831/531 Settlement will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates, pursuant to the following provisions. The process for determining future reductions in Tier 1 load and cost allocations to Rate 531 shall be as follows: (a) the relevant comparison is between end of test year in prior rate case and end of test year in subsequent rate case; (b) the measure of costs for legacy coal assets includes capital balances for coal assets, as well as fixed O&M, coal inventory, and other base rate inclusions; (c) the starting point is the proposed Rate 531 tariff terms and conditions, 180 MW of Rate 531 class demand, and 170 MWs of Rate 531 contract demand commitments per the Rate 831/531 Settlement, and the eventual end point, based on the current composition of the class, is 70 MW of both Rate 531 Tier 1 class demand and actual contract demand, with future proportional adjustments reducing the prevailing 110 MW differential between the current Rate 531 class demand and the end point; (d) consistent with the Rate 831/531 Settlement, successive future adjustments will involve both reductions in Tier 1 Rate 531 class allocations and contract demand commitments to progressively narrow the spread between allocated Rate 531 class demand and actual contract demand for the class; and (e) the above methodology assumes existing class composition throughout legacy coal asset recovery period, subject to an agreed process to address any material changes in circumstance. Nothing in this Agreement shall obligate a class member to increase its Tier 1 contract demand commitments in the future.

(g) Material Changes in Circumstances. The signatories to the Rate 831/531 Settlement and OUCC will meet and confer in the event of any material change of circumstances affecting the composition of the class or the class load, with the following clarifications: (a) no class member is prohibited from exiting the rate upon expiration of the contractual term; (b) existing tariff provisions on modifying commitments in the event of a facility closure remain in force; (c) in the event a class member exits the rate, the allocated demand and total contracted demand for the class will be reduced correspondingly provided that the exiting customer is migrating to another rate schedule with a like firm demand or the exit from Rate 531 is attributable to a facility closure or material reduction in load; (d) in the event that a class member increases Tier 1 load then other class members not at tariff minimum may decrease Tier 1 commitments correspondingly to maintain class load at agreed levels; (e) in the event a new customer joins the rate class then existing customers with firm demand above the tariff minimum will be permitted to reduce Tier 1 commitments so long as the class load is maintained at the agreed levels; and (f) recognizing that not all contingencies can be anticipated and addressed in advance, any signatory to the Rate 831/531 Settlement or the OUCC may initiate discussions in the event of a material change of circumstances and, absent agreement, may submit the issue for resolution by the Commission.

(h) Rate 526. Considering that significant amounts of demand costs are being recovered through the energy charge, the revenue reduction as a result of this

Agreement that is allocated to Rate 526 will be used to reduce the energy charge until all energy and demand components of Rate 526 match NIPSCO's energy/demand cost of service levels.

(i) Customer Charges. Customer charges proposed by NIPSCO shall be approved, except NIPSCO's existing monthly charge for Rate 511 shall be increased to $14.00 and the existing monthly charge for Rate 521 shall be increased to $32.50.

(j) Multi Family Rate. NIPSCO will collect data on residential customer housing types to identify multi-family customers and analyze cost differentials between single- and multi-family residential customers. NIPSCO will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, NIPSCO will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested stakeholder the results of its analysis.

(k) Rate 532. As part of preparing cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of the Rate 532 class of customers to determine if adjustments to this rate or the creation of another rate for current customers in Rate 532 is appropriate. This review will include, but will not be limited to, a review of the appropriate minimum demand level for participation in Rate 532 and demand blocks and demand and energy charges. NIPSCO will make this

information available to any member of this rate class and/or their consultants who request such information.

(l) Rate 550. The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511.

(m) Survival of Terms of Paragraphs 4(f) and 7(f) and (g). The terms in Paragraphs 4(f) and 7(f) and (g) relating to O&M reduction relating to Schahfer fire, future reductions in Tier 1 load, and cost allocations to Rate 531, shall survive the termination of this Agreement.

8. Low Income Program and Issues. NIPSCO agrees to withdraw its proposed Low Income Program. However, NIPSCO retains the right to seek approval of a low income program in the future. In recognition of concerns expressed by the OUCC and CAC, NIPSCO will contribute below the line (*i.e.*, not to be recovered through rates) a total of $400,000 to Indiana Community Action Association for the Community Action Programs to enable Community Action Program health and safety work for the low income weatherization program. These contributions will be made in $100,000 increments in calendar years 2024, 2025, 2026, and 2027.

9. Distributed Generation. As part of the annual Performance Metrics Report filed pursuant to the Commission's July 18, 2016 Order in Cause No. 44688, NIPSCO agrees to include monthly data that separately provides data on Excess

Distributed Generation tariff and Small Power Production tariff customer participation, broken down by residential and non-residential customers, and including data on both new and total (a) capacity (kW-ac) installed, (b) number of customers, and (c) size of battery storage system (both kW and kWh) if one is part of the customer's system.

10. Demand Response. NIPSCO will continue to work with its Energy Efficiency Oversight Board ("OSB") on appropriate demand response programs. NIPSCO will work with its OSB on how best to model demand response for its next integrated resource plan, including but not limited to inclusion in the demand side management market potential study. NIPSCO will work with its OSB to do a request for proposals for demand response programs, either as part of an all-source request for proposals or as a stand-alone event.

11. Infrastructure Investment and Jobs Act ("IIJA") / Inflation Reduction Act ("IRA"). NIPSCO will meet with CAC and other interested stakeholders to evaluate potential opportunities associated with the IIJA and IRA that could be reasonably pursued by NIPSCO to the benefit of NIPSCO's customers. NIPSCO will provide CAC and other interested stakeholders with the results of its evaluation and provide the parties the opportunity to comment on NIPSCO's evaluation. Meetings will begin within 60 days of execution of this Agreement.

12. Indiana Municipal Utility Group.[13] IMUG is agreeing to not oppose this Agreement for the consideration and commitments contained in Addendum A, which provisions the Settling Parties agree to support or not oppose.

13. RV Users Group. The RV Group is signing this Agreement to receive the benefits contained herein and for the consideration and commitments contained in Addendum B, which NIPSCO agrees to support, but which other Settling Parties will not oppose. With respect to the RV Group TDSIC provisions in Addendum B, the Settling Parties (other than NIPSCO) take no position on and do not endorse such provisions but will not oppose them.

14. Other Relief Requested by NIPSCO. The Settling Parties agree that all other aspects of NIPSCO's case-in-chief, as modified in its rebuttal testimony, should be approved.

C. Procedural Aspects and Presentation of the Agreement

1. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the simplification and minimization of issues to be presented in the proceeding.

2. The Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding and agree to assist and cooperate in the

[13] Indiana Municipal Utility Group is comprised of Towns of Schererville, Dyer, and the City of East Chicago.

preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval. All evidence which has been prefiled by the Settling Parties will be admitted into the record. All Settling Parties waive cross-examination on all witnesses of other Settling Parties but reserve the right to ask questions of any witness who may be cross-examined by a non- settling party.

3. The concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of material condition deemed unacceptable to any Settling Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications. If the Agreement is withdrawn, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. In the event the Agreement is withdrawn, the Settling Parties will request an Attorney's Conference to be convened to establish a procedural schedule for the continued litigation of this proceeding.

4. The Settling Parties acknowledge that this Settlement Agreement addresses all issues in the proceeding, including the appropriate revenue requirement and allocation of costs, and includes compromises upon the part of each Settling Party. The Settling Parties agree that this Agreement and each term, condition, amount,

methodology, and exclusion contained herein (a) reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement; (b) has accounted for the overall level of risk presented to NIPSCO by the Settlement Agreement; and (c) is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and the Final Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

5. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Agreement as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it, without objection.

6. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

7. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement, and the Settling Parties shall not support any appeal of any portion of the of Final Order by any person not a party to this Agreement.

8. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

9. The terms set forth in this Agreement are the complete and final agreement among the Settling Parties. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 10th day of March, 2023.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Office of Utility Consumer Counselor

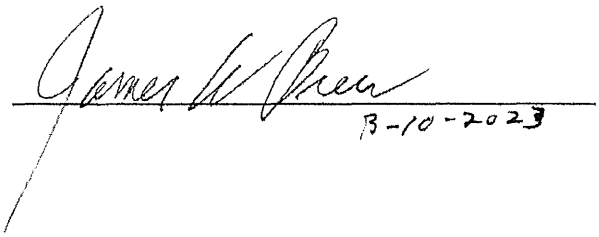


William Fine
Utility Consumer Counselor
Indiana Office of Utility Consumer Counselor
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204

NIPSCO Industrial Group



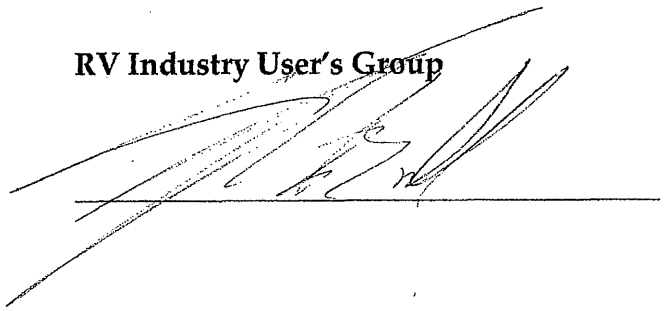
NLMK Indiana



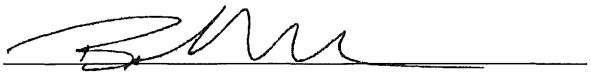
United States Steel Corporation

Kristina Kern Wheeler

RV Industry User's Group



Walmart Inc.



Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	**Operating Revenue**							
2	Revenue (Actual / Pro Forma)	$ 1,700,765,620		REV, Col A	$ 1,505,336,512	261,923,892	PF - 1 - S	$ 1,767,260,404
3	Pro forma Adjustments December 31, 2021		(19,779,195)	REV, Col B				
4	Budget Adjustments December 31, 2022		(51,640,914)	REV, Col D				
5	Budget Adjustments December 31, 2023		19,012,369	REV, Col F				
6	Ratemaking Adjustments December 31, 2023		(143,021,367)	REV-S, Col H				
7	Total Operating Revenue	$ 1,700,765,620	$ (195,429,108)		$ 1,505,336,512	$ 261,923,892		$ 1,767,260,404
8	**Fuel & Purchased Power**							
9	Fuel Cost (Actual / Pro Forma)	$ 416,398,339		COGS, Col A	$ 367,509,634	-		$ 367,509,634
10	Pro forma Adjustments December 31, 2021		(3,843,760)	COGS, Col B				
11	Budget Adjustments December 31, 2022		(25,895,162)	COGS, Col D				
12	Budget Adjustments December 31, 2023		(4,860,689)	COGS, Col F				
13	Ratemaking Adjustments December 31, 2023		(14,289,094)	COGS-S, Col H				
14	Total Fuel and Purchased Power Costs	$ 416,398,339	$ (48,888,705)		$ 367,509,634			$ 367,509,634
15	**Gross Margin**	$ 1,284,367,281	$ (146,540,403)		$ 1,137,826,878	$ 261,923,892		$ 1,399,750,770
16	**Operations and Maintenance Expenses**							
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 493,605,075		O&M, Col A	$ 488,572,809	671,748	PF - 2 - S	$ 489,244,558
18	Pro forma Adjustments December 31, 2021		(23,438,011)	O&M, Col B				
19	Budget Adjustments December 31, 2022		44,307,375	O&M, Col D				
20	Budget Adjustments December 31, 2023		42,240,218	O&M, Col F				
21	Ratemaking Adjustments December 31, 2023		(68,141,848)	O&M-S, Col H				
22	Total Operations and Maintenance Expense	$ 493,605,075	$ (5,032,265)		$ 488,572,809	$ 671,748		$ 489,244,558
23	**Depreciation Expense**							
24	Depreciation Expense (Actual / Pro Forma)	$ 300,041,895		DEPR, Col A	$ 286,232,067			$ 286,232,067
25	Pro forma Adjustments December 31, 2021		(10,408,351)	DEPR, Col B				
26	Budget Adjustments December 31, 2022		4,307,754	DEPR, Col D				
27	Budget Adjustments December 31, 2023		19,336,047	DEPR, Col F				
28	Ratemaking Adjustments December 31, 2023		(27,045,278)	DEPR-S, Col H				
29	Total Depreciation Expense	$ 300,041,895	$ (13,809,828)		$ 286,232,067	$ -		$ 286,232,067

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
30	**Amortization Expense**							
31	Amortization Expense (Actual / Pro Forma)	$ 28,049,666		AMTZ, Col A	$ 118,760,693			$ 118,760,693
32	Pro forma Adjustments December 31, 2021		33,681,838	AMTZ, Col B				
33	Budget Adjustments December 31, 2022		35,261,815	AMTZ, Col D				
34	Budget Adjustments December 31, 2023		20,002,648	AMTZ, Col F				
35	Ratemaking Adjustments December 31, 2023		1,764,724	AMTZ-S, Col H				
36	Total Amortization Expense	$ 28,049,666	$ 90,711,026		$ 118,760,693	$ -		$ 118,760,693
37	**Taxes**							
38	**Taxes Other than Income**							
39	Taxes Other than Income (Actual / Pro Forma)	$ 56,893,980		OTX, Col A	$ 35,531,910			$ 35,531,910
40	Pro forma Adjustments December 31, 2021		(608,134)	OTX, Col B				
41	Budget Adjustments December 31, 2022		11,539,562	OTX, Col D				
42	Budget Adjustments December 31, 2023		(609,441)	OTX, Col F				$ -
43	Ratemaking Adjustments December 31, 2023		(31,684,057)	OTX, Col H		334,236	PF - 3 - S	$ 334,236
44	Total Taxes Other Than Income	$ 56,893,980	$ (21,362,070)		$ 35,531,910	$ 334,236		$ 35,866,145
45	**Operating Income Before Income Taxes**	$ 405,776,664	$ (197,047,265)		$ 208,729,399	$ 260,917,908		$ 469,647,307
46	**Income Taxes**							
47	Federal and State Taxes (Actual / Pro Forma)	$ 55,596,061	(53,742,587)	Attachment 3-C-S, ITX 1-S	$ 1,853,474	64,892,893	PF - 4 - S	$ 66,746,367
48	Total Taxes	$ 112,490,040	$ (75,104,657)		$ 37,385,384	$ 65,227,129		$ 102,612,512
49	**Total Operating Expenses including Income Taxes**	$ 934,186,677	$ (3,235,724)		$ 930,950,953	$ 65,898,877		$ 996,849,830
50	**Required Net Operating Income**	$ 350,180,604	$ (143,304,679)		$ 206,875,925	$ 196,025,015		$ 402,900,940

Footnote 1 - Unless otherwise noted

Northern Indiana Public Service Company LLC
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2023

Line No.	Description	Revenue Deficiency
1	Net Original Cost Rate Base	$ 5,925,013,822
2	Rate of Return	6.80%
3	Net Operating Income	$ 402,900,940
4	Pro forma Net Operating Income	$ 206,875,925
5	Increase in Net Operating Income (NOI Shortfall)	$ 196,025,015
6	Effective Incremental Revenuel NOI Conversion Factor	74.84%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	$ 261,923,892

8	One		1.000000			
9	Less: Public Utility Fee		0.001276			
10	Less: Bad Debt		0.002565			
11	State Taxable Income			0.996159		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	-				
14	Taxable Adjusted Gross Income Tax		0.996159			
15	Adjusted Gross Income Tax Rate		0.049000			
16	Adjusted Gross Income Tax			0.048812		
17	Line 11 less line 13 less line 16				0.947347	
18	One			1.000000		
19	Less: Federal Income Tax Rate			0.210000		
20	One Less Federal Income Tax Rate				0.790000	
21	Effective Incremental Revenue / NOI Conversion Factor					74.840%

Northern Indiana Public Service Company LLC
Summary of Rate Base
As Of December 31, 2023

Line No.	Description		Pro forma As Of December 31, 2023	Attachment 3-B-S2-S Reference
	Rate Base			
1	Utility Plant	$	8,252,008,653	RB, Col I
2	Common Allocated		384,894,416	RB, Col I
3	**Total Utility Plant**	$	**8,636,903,069**	RB, Col I
4	Accumulated Depreciation and Amortization		(4,069,667,383)	RB, Col I
5	Common Allocated		(245,419,231)	RB, Col I
6	**Total Accumulated Depreciation and Amortization**	$	**(4,315,086,614)**	RB, Col I
7	**Net Utility Plant**	$	**4,321,816,455**	RB, Col I
8	RMS Unit 14/15 Retirement	$	593,022,393	RB, Col I
9	Joint Venture Reg Assets		817,299,925	RB, Col I
10	Reg Assets - Cause 44688 & 45159		23,510,338	RB, Col I
11	Electric 2021-2026 TDSIC Plan Cause #45557		24,558,486	RB, Col I
12	FMCA - Post 45159 & CCR Remediation		545,389	RB, Col I
13	Materials & Supplies		98,989,010	RB, Col I
14	Production Fuel		45,271,825	RB, Col I
15	**Total Rate Base**	$	**5,925,013,822**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure - S2
As Of December 31, 2023

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	$ 4,564,821,051	51.63%	9.80%	5.06%
2	Long-Term Debt	3,233,952,976	36.58%	4.66%	1.70%
3	Customer Deposits	59,541,950	0.67%	5.63%	0.04%
4	Deferred Income Taxes	1,393,665,855	15.76%	0.00%	0.00%
5	Post-Retirement Liability	13,945,116	0.16%	0.00%	0.00%
6	Prepaid Pension Asset	(424,946,780)	-4.81%	0.00%	0.00%
7	Post-1970 ITC	640,278	0.01%	7.67%	0.00%
8	Totals	**$ 8,841,620,445**	**100.00%**		**6.80%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 4,564,821,051	58.53%	9.80%	5.74%
10	Long-Term Debt	3,233,952,976	41.47%	4.66%	1.93%
11	**Totals**	**$ 7,798,774,027**	**100.00%**		**7.67%**

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	**Operating Revenue**							
2	Revenue (Actual / Pro Forma)	$ 1,700,765,620		REV, Col A	$ 1,505,336,512	291,804,089	PF - 1- S-ALT	$ 1,797,140,601
3	Pro forma Adjustments December 31, 2021		(19,779,195)	REV, Col B				
4	Budget Adjustments December 31, 2022		(51,640,914)	REV, Col D				
5	Budget Adjustments December 31, 2023		19,012,369	REV, Col F				
6	Ratemaking Adjustments December 31, 2023		(143,021,367)	REV-S, Col H				
7	Total Operating Revenue	$ 1,700,765,620	$ (195,429,108)		$ 1,505,336,512	$ 291,804,089		$ 1,797,140,601
8	**Fuel & Purchased Power**							
9	Fuel Cost (Actual / Pro Forma)	$ 416,398,339		COGS, Col A	$ 367,509,634	-		$ 367,509,634
10	Pro forma Adjustments December 31, 2021		(3,843,760)	COGS, Col B				
11	Budget Adjustments December 31, 2022		(25,895,162)	COGS, Col D				
12	Budget Adjustments December 31, 2023		(4,860,689)	COGS, Col F				
13	Ratemaking Adjustments December 31, 2023		(14,289,094)	COGS-S, Col H				
14	Total Fuel and Purchased Power Costs	$ 416,398,339	$ (48,888,705)		$ 367,509,634			$ 367,509,634
15	**Gross Margin**	$ 1,284,367,281	$ (146,540,403)		$ 1,137,826,878	$ 291,804,089		$ 1,429,630,966
16	**Operations and Maintenance Expenses**							
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 493,605,075		O&M, Col A	$ 518,338,243	748,381	PF - 2 - S-ALT	$ 519,086,625
18	Pro forma Adjustments December 31, 2021		(23,438,011)	O&M, Col B				
19	Budget Adjustments December 31, 2022		44,307,375	O&M, Col D				
20	Budget Adjustments December 31, 2023		42,240,218	O&M, Col F				
21	Ratemaking Adjustments December 31, 2023		(38,376,414)	O&M-S, Col H				
22	Total Operations and Maintenance Expense	$ 493,605,075	$ 24,733,169		$ 518,338,243	$ 748,381		$ 519,086,625
23	**Depreciation Expense**							
24	Depreciation Expense (Actual / Pro Forma)	$ 300,041,895		DEPR, Col A	$ 286,232,067			$ 286,232,067
25	Pro forma Adjustments December 31, 2021		(10,408,351)	DEPR, Col B				
26	Budget Adjustments December 31, 2022		4,307,754	DEPR, Col D				
27	Budget Adjustments December 31, 2023		19,336,047	DEPR, Col F				
28	Ratemaking Adjustments December 31, 2023		(27,045,278)	DEPR-S, Col H				
29	Total Depreciation Expense	$ 300,041,895	$ (13,809,828)		$ 286,232,067	$ -		$ 286,232,067

Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2023

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates
30	**Amortization Expense**							
31	Amortization Expense (Actual / Pro Forma)	$ 28,049,666		AMTZ, Col A	$ 118,760,693			$ 118,760,693
32	Pro forma Adjustments December 31, 2021		33,681,838	AMTZ, Col B				
33	Budget Adjustments December 31, 2022		35,261,815	AMTZ, Col D				
34	Budget Adjustments December 31, 2023		20,002,648	AMTZ, Col F				
35	Ratemaking Adjustments December 31, 2023		1,764,724	AMTZ-S, Col H				
36	Total Amortization Expense	$ 28,049,666	$ 90,711,026		$ 118,760,693	$ -		$ 118,760,693
37	**Taxes**							
38	**Taxes Other than Income**							
39	Taxes Other than Income (Actual / Pro Forma)	$ 56,893,980		OTX, Col A	$ 35,531,910			$ 35,531,910
40	Pro forma Adjustments December 31, 2021		(608,134)	OTX, Col B				
41	Budget Adjustments December 31, 2022		11,539,562	OTX, Col D				
42	Budget Adjustments December 31, 2023		(609,441)	OTX, Col F		-		$ -
43	Ratemaking Adjustments December 31, 2023		(31,684,057)	OTX, Col H		372,365	PF - 3 - S-ALT	$ 372,365
44	Total Taxes Other Than Income	$ 56,893,980	$ (21,362,070)		$ 35,531,910	$ 372,365		$ 35,904,275
45	**Operating Income Before Income Taxes**	$ 405,776,664	$ (226,812,699)		$ 178,963,965	$ 290,683,342		$ 469,647,307
46	**Income Taxes**							
47	Federal and State Taxes (Actual / Pro Forma)	$ 55,596,061	(61,145,548)	Attachment 3-C-S, ITX 1 - S-ALT	$ (5,549,487)	72,295,854	PF - 4 - S-ALT	$ 66,746,367
48	Total Taxes	$ 112,490,040	$ (82,507,618)		$ 29,982,423	$ 72,668,219		$ 102,650,642
49	**Total Operating Expenses including Income Taxes**	$ 934,186,677	$ 19,126,749		$ 953,313,426	$ 73,416,601		$ 1,026,730,026
50	**Required Net Operating Income**	$ 350,180,604	$ (165,667,152)		$ 184,513,452	$ 218,387,488		$ 402,900,940

Footnote 1 - Unless otherwise noted

Northern Indiana Public Service Company LLC
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2023

Line No.	Description					Revenue Deficiency
1	Net Original Cost Rate Base					$ 5,925,013,822
2	Rate of Return					6.80%
3	Net Operating Income					$ 402,900,940
4	Pro forma Net Operating Income					$ 184,513,452
5	Increase in Net Operating Income (NOI Shortfall)					$ 218,387,488
6	Effective Incremental Revenuel NOI Conversion Factor					74.84%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)					$ 291,804,089
8	One		1.000000			
9	Less: Public Utility Fee		0.001276			
10	Less: Bad Debt		0.002565			
11	State Taxable Income			0.996159		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	-				
14	Taxable Adjusted Gross Income Tax		0.996159			
15	Adjusted Gross Income Tax Rate		0.049000			
16	Adjusted Gross Income Tax			0.048812		
17	Line 11 less line 13 less line 16				0.947347	
18	One			1.000000		
19	Less: Federal Income Tax Rate			0.210000		
20	One Less Federal Income Tax Rate				0.790000	
21	Effective Incremental Revenue / NOI Conversion Factor					74.840%

Northern Indiana Public Service Company LLC
Summary of Rate Base
As Of December 31, 2023

Line No.	Description		Pro forma As Of December 31, 2023	Attachment 3-B-S2-S Reference
	Rate Base			
1	Utility Plant	$	8,252,008,653	RB, Col I
2	Common Allocated		384,894,416	RB, Col I
3	**Total Utility Plant**	**$**	**8,636,903,069**	RB, Col I
4	Accumulated Depreciation and Amortization		(4,069,667,383)	RB, Col I
5	Common Allocated		(245,419,231)	RB, Col I
6	**Total Accumulated Depreciation and Amortization**	**$**	**(4,315,086,614)**	RB, Col I
7	**Net Utility Plant**	**$**	**4,321,816,455**	RB, Col I
8	RMS Unit 14/15 Retirement	$	593,022,393	RB, Col I
9	Joint Venture Reg Assets		817,299,925	RB, Col I
10	Reg Assets - Cause 44688 & 45159		23,510,338	RB, Col I
11	Electric 2021-2026 TDSIC Plan Cause #45557		24,558,486	RB, Col I
12	FMCA - Post 45159 & CCR Remediation		545,389	RB, Col I
13	Materials & Supplies		98,989,010	RB, Col I
14	Production Fuel		45,271,825	RB, Col I
15	**Total Rate Base**	**$**	**5,925,013,822**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure
As Of December 31, 2023

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	$ 4,564,821,051	51.63%	9.80%	5.06%
2	Long-Term Debt	3,233,952,976	36.58%	4.66%	1.70%
3	Customer Deposits	59,541,950	0.67%	5.63%	0.04%
4	Deferred Income Taxes	1,393,665,855	15.76%	0.00%	0.00%
5	Post-Retirement Liability	13,945,116	0.16%	0.00%	0.00%
6	Prepaid Pension Asset	(424,946,780)	-4.81%	0.00%	0.00%
7	Post-1970 ITC	640,278	0.01%	7.67%	0.00%
8	Totals	**$ 8,841,620,445**	**100.00%**		**6.80%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 4,564,821,051	58.53%	9.80%	5.74%
10	Long-Term Debt	3,233,952,976	41.47%	4.66%	1.93%
11	**Totals**	**$ 7,798,774,027**	**100.00%**		**7.67%**

Addendum A

Settlement Agreement Addendum Responsive to the Indiana Municipal Utility Group ("IMUG") Recommendations[1]

1) IMUG will in writing not oppose the Settlement Agreement in Cause No. 45772. This includes IMUG and all Settling or not opposing Parties waiving cross-examination of all Settling Parties' witnesses, but IMUG reserves the right to ask questions of any witness that does appear and is crossed by a non-settling party, or crossed in a manner contrary to IMUG's benefits from this Settlement.

2) Streetlights provide essential important public service benefits through nighttime public safety and through promotion of nighttime economic development and social activities. Those public service benefits are further enhanced through the superior lighting provided by modern LED streetlights. NIPSCO's municipal electric customers are public services providers who pay for street lighting and an array of other essential public services through limited municipal budgets without profit motivation. Those municipal streetlight public service efforts primarily benefit and protect NIPSCO area residents. As such it is agreed that:

3) NIPSCO will fund energy efficiency audits and new efficiency measures including LEDs for each of the three participating municipality members of IMUG (as of March 3, 2023), at a maximum cost of up to $25,000 per municipality. NIPSCO will work with the IMUG members to choose a mutually agreeable company or consultant to perform these energy efficiency audits. If a program or project qualifies for NIPSCO's energy efficiency program, this will qualify as a "new energy efficiency measure" under this term, and the customer cost (after rebate) would qualify for reimbursement under this term. NIPSCO and the municipalities will work in good faith as to what qualifies as a "new energy efficiency measure."

4) The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511 as stipulated in Section 7 (l) of the Settlement Agreement.

5) NIPSCO will lend its expertise to any IMUG member that seeks to convert customer-owned streetlights to LEDs, e.g., meetings, exchange of info, sharing access to consultants for learning and knowledge, etc.

6) NIPSCO will work with IMUG to seek to improve its record keeping for LED and HPS street lighting so that the records will differentiate between the type of fixture (*e.g.*, LED, MV, HPS) and the type of repair made.

---

[1] Indiana Municipal Utility Group is comprised of Towns of Schererville, Dyer, and the City of East Chicago.

Addendum A

ACCEPTED AND AGREED this 10th day of March, 2023.

[SIGNATURE PAGES FOLLOW]

Addendum A

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Municipal Utility Group

Theodore J Sommer

Addendum B

Settlement Terms between NIPSCO and the RV Industry User's Group ("RV Group")[1]

1) NIPSCO has already begun work on necessary steps to update and upgrade the Mingus Ditch substation which is a required precursor step to system redundancies and reliability improvements in the Goshen/Elkhart County service territory. To the extent feasible, NIPSCO will also speed up the construction of the two substation projects that are discussed in Ronald Talbot's rebuttal testimony in this proceeding (2025 and 2026 projects, which are already identified in and are part of NIPSCO's approved electric TDSIC Plan).

2) NIPSCO commits to fund energy efficiency audits of up to $50,000 per customer for each of the four RV Group members. NIPSCO and the RV Group members will work together to select a mutually satisfactory, qualified company or consultant to perform these energy efficiency audits and to coordinate to ensure viable and cost effective energy efficient proposals and opportunities are identified.

3) NIPSCO agrees to include RV Group representatives in discussions with the DSM Oversight Board related to participating in existing or proposing additional demand response program opportunities available to or that could be expanded to provide additional benefits to RV Group Members and lower NIPSCO peak energy needs. NIPSCO is separately committed to issuing an RFI and/or RFI for demand response as part of its next RFP that shall include and allow for RV Group member proposals consistent with these objectives.

4) NIPSCO will, separately from the DSM Oversight Board process, directly work with and assist the RV Group representatives in determining potential savings, programs, and funding opportunities through its DSM program and any other available Commission-approved processes. To the extent savings are identified that are not current DSM or other programs/measures, NIPSCO will make a good faith effort to add such program/measure to its DSM plan(s).

5) As part of preparing its cost of service for its next electric base rate case, NIPSCO will study operational and usage characteristics of each of the Members of the RV Group to determine if a new or adjusted rate schedule is appropriate for these customers and customers of similar characteristics who

---

[1] The RV Industry User's Group is comprised of LCI Industries, Inc.; Patrick Industries, Inc.; Forest River, Inc.; and Keystone RV Company.

would qualify. As part of these efforts, NIPSCO agrees to make any relevant information available to the RV Group and/or their consultants.

6) As part of its next electric base rate case, subject to any necessary non-disclosure protections, NIPSCO agrees to prepare a 4CP cost of service analysis for purposes allocating production-related costs and make this available to the RV Group in advance of such filing, as well as to any other party subsequently participating in the case who requests it. This analysis shall conform to and be consistent with the principles of cost causation identified by NIPSCO in this and NIPSCO's last base rate case in Cause No. 45159. This does not, however, limit NIPSCO in determining which cost of service analysis it chooses to propose in its case-in-chief, nor does it impact any other parties' right to take any position with regards to cost of service or allocations in that next rate case.

7) NIPSCO commits to meeting with RV Group representatives to review and discuss cost of service concerns before NIPSCO files its next electric base rate case is filed.

RV Group TDSIC Project(s)

8) NIPSCO and the RV Group agree that the RV Group may propose one or more projects to be included as part of NIPSCO's TDSIC Plan (currently under Cause No. 45557) totaling up to $3.5 million, provided each project meets the applicable requirements of the TDSIC Statute (Ind. Code ch. 8-1-39). This agreed upon commitment and benefit shall be reserved for the benefit of the RV Group Members and any TDSIC Plan request made by an RV Group Member shall be for qualifying infrastructure upgrade needs that improve reliability and/or spur economic development, which include, but are not limited to upgrades to substations, transformers, distribution and transmission facilities, or other necessary electrical system upgrades to provide service to an RV Group member ("RV Group TDSIC Project(s)"). NIPSCO shall seek approval for inclusion of such RV Group TDSIC Projects and the related funding as part of NIPSCO's TDSIC Plan. To manage the allocation of the RV Group TDSIC Project(s), a Fund shall be pursued as part of NIPSCO's existing TDSIC process. The Fund shall not lapse or be transferred to other NIPSCO customers, but any NIPSCO system upgrades or facilities built to support any RV Group TDSIC Project(s) may also be used to serve other customers, provided this does not diminish service reliability for the RV Group TDSIC Project(s), and the Fund shall continue until fully disbursed for RV Group TDSIC Project(s).

9) RV Group TDSIC Project(s) shall include any-and-all projects that qualify under the TDSIC Statute. NIPSCO will file for approval of the RV Group TDSIC Project(s) to allow the RV Group TDSIC Projects to include as many qualifying types of projects as possible, including: (i) RV Group operation or production facility updates or expansions that will result in continued or increased energy demand or continued or increased employment by the applying RV Group member from new capital investments made within the NIPSCO service territory; (ii) support of RV Group member renewable energy projects, energy efficiency and demand response, or peak load reduction projects; and (iii) any advanced or smart meter technology that will assist an RV Group member in reducing peak load. To the extent that a project proposed by an RV Group member does not qualify under the TDSIC Statute but would qualify under NIPSCO's demand side management ("DSM") tracker, NIPSCO will seek inclusion of qualifying projects in the DSM tracker, and these projects would not count against the $3.5 million total RV Group TDSIC Project amount.

10) Each of the RV Group members shall be entitled to request one or more RV Group TDSIC Project(s) subject to the review and support of NIPSCO, which support and approval shall not be unreasonably withheld or delayed. Any requests to support RV Group TDSIC Project(s) from the Fund will be presented in a tracker filing by NIPSCO in Cause No. 45557-TDSIC-X (or successor docket), which will require and provide a sufficient evidentiary showing consistent with the TDSIC Statute for the approval of such amounts.

11) Notwithstanding the provisions of paragraph B.13 of the Stipulation and Settlement Agreement, all other participating parties in the then-pending TDSIC docket shall be provided notice of and reserve the right to timely take any position on such RV Group TDSIC Project(s) funding request when the request is formally presented in the TDSIC tracker filing.

12) NIPSCO and the RV Group shall work together in good faith to establish precise administrative details for applications or requests for RV Group TDSIC Project(s), and such applications or requests can be made any time after approval of the Settlement Agreement, consistent with the language and requirements herein.

ACCEPTED AND AGREED this 10th day of March, 2023.

[SIGNATURE PAGES FOLLOW]

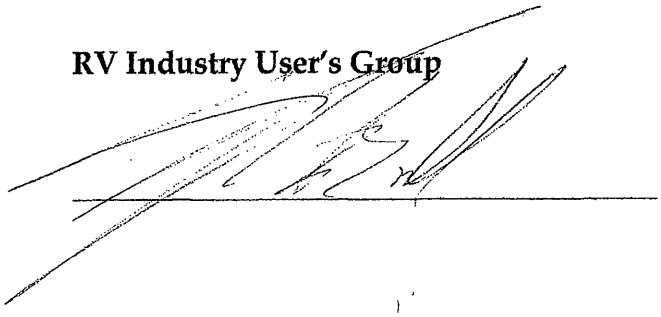
Addendum B

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Attachment A

RV Industry User's Group



NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
STEAM PRODUCTION PLANT									
311.00 STRUCTURES AND IMPROVEMENTS									
MICHIGAN CITY GENERATING STATION	12-2026	110-R2.5 *	(8)	51,562,435.54	17,998,984	37,688,446	3,589,376 **	6.96	10.5
MICHIGAN CITY - UNIT 12	12-2026	110-R2.5 *	(8)	105,612,033.98	34,465,564	79,595,433	7,580,517 **	7.18	10.5
R M SCHAHFER GENERATING STATION	12-2025	110-R2.5 *	(11)	127,915,344.56	46,961,777	95,024,255	9,049,929 **	7.07	10.5
R M SCHAHFER - UNIT 14	12-2021	110-R2.5 *	(11)	7,254,940.91	8,052,984	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	110-R2.5 *	(11)	8,973,687.98	9,960,794	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	110-R2.5 *	(11)	142,375,381.48	59,259,829	98,776,845	9,407,319 **	6.61	10.5
R M SCHAHFER - UNIT 18	12-2025	110-R2.5 *	(11)	66,503,875.56	27,117,452	46,701,850	4,447,795 **	6.69	10.5
SUGAR CREEK	06-2068	110-R2.5 *	(20)	8,313,732.16	971,170	9,005,309	209,207	2.52	43.0
TOTAL ACCOUNT 311				518,511,432.17	204,788,554	366,792,138	34,284,143	6.61	10.7
BOILER PLANT EQUIPMENT									
312.10 BOILER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2026	55-S0 *	(8)	113,680,109.39	41,230,199	81,544,319	7,766,126 **	6.83	10.5
MICHIGAN CITY - UNIT 12	12-2026	55-S0 *	(8)	228,859,600.56	75,477,700	171,690,669	16,351,492 **	7.14	10.5
R M SCHAHFER GENERATING STATION	12-2025	55-S0 *	(11)	84,292,339.39	26,568,061	66,996,436	6,380,613 **	7.57	10.5
R M SCHAHFER - UNIT 14	12-2021	55-S0 *	(11)	49,723,376.18	55,192,948	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	55-S0 *	(11)	33,603,926.03	37,300,358	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	55-S0 *	(11)	202,359,699.26	79,151,905	145,467,361	13,854,034 **	6.85	10.5
R M SCHAHFER - UNIT 18	12-2025	55-S0 *	(11)	201,099,271.43	79,004,423	144,215,768	13,734,835 **	6.83	10.5
SUGAR CREEK	06-2068	55-S0 *	(20)	94,097,828.91	11,111,311	101,806,084	2,971,726	3.16	34.3
TOTAL ACCOUNT 312.1				1,007,716,151.15	405,036,905	711,720,637	61,058,826	6.06	11.7
312.20 BOILER PLANT - MOBILE FUEL HDLG/STRG									
MICHIGAN CITY GENERATING STATION	12-2026	55-S0 *	(8)	8,288,460.63	3,366,998	5,584,539	531,861 **	6.42	10.5
MICHIGAN CITY - UNIT 12	12-2026	55-S0 *	(8)	798,597.22	334,235	528,250	50,310 **	6.30	10.5
R M SCHAHFER GENERATING STATION	12-2025	55-S0 *	(11)	17,364,935.22	7,709,401	11,565,677	1,101,493 **	6.34	10.5
TOTAL ACCOUNT 312.2				26,451,993.07	11,410,634	17,678,466	1,683,664	6.36	10.5
312.30 BOILER PLANT - UNIT TRAIN COAL CARS									
R M SCHAHFER GENERATING STATION		25-R2.5	0	1,443,972.95	148,395	1,295,578	123,388 **	8.55	10.5
312.40 BOILER PLANT - SO2 PLANT EQUIPMENT									
MICHIGAN CITY - UNIT 12	12-2026	55-S0 *	(8)	215,728,527.65	70,548,260	162,438,550	15,470,338 **	7.17	10.5
R M SCHAHFER GENERATING STATION	12-2025	55-S0 *	(11)	17,157,480.64	4,299,910	14,744,894	1,404,276 **	8.18	10.5
R M SCHAHFER - UNIT 14	12-2021	55-S0 *	(11)	6,435,509.61	7,143,416	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	55-S0 *	(11)	23,150,634.50	25,697,204	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	55-S0 *	(11)	77,536,922.09	33,963,354	52,102,630	4,962,155 **	6.40	10.5
R M SCHAHFER - UNIT 18	12-2025	55-S0 *	(11)	67,825,904.31	29,937,648	45,349,106	4,318,962 **	6.37	10.5
TOTAL ACCOUNT 312.4				407,834,978.80	171,589,792	274,635,180	26,155,731	6.41	10.5
312.50 BOILER PLANT - COAL PILE BASE									
MICHIGAN CITY GENERATING STATION	12-2026	55-S0 *	(8)	785,602.93	204,909	643,542	61,290 **	7.80	10.5
R M SCHAHFER - UNIT 17	12-2025	55-S0 *	(11)	1,200,088.24	373,831	958,267	91,264 **	7.60	10.5
R M SCHAHFER - UNIT 18	12-2025	55-S0 *	(11)	1,300,434.47	380,372	1,063,110	101,249 **	7.79	10.5
TOTAL ACCOUNT 312.5				3,286,125.64	959,112	2,664,919	253,803	7.72	10.5
TOTAL ACCOUNT 312				1,446,733,221.61	589,144,838	1,007,994,780	89,275,412	6.17	11.3

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
314.00 TURBOGENERATOR UNITS									
MICHIGAN CITY GENERATING STATION	12-2026	60-R2 *	(8)	1,514,710.15	648,262	987,625	94,060 **	6.21	10.5
MICHIGAN CITY - UNIT 12	12-2026	60-R2 *	(8)	97,603,289.17	36,747,168	68,664,384	6,539,465 **	6.70	10.5
R M SCHAHFER GENERATING STATION	12-2025	60-R2 *	(11)	13,617,782.83	3,142,627	11,973,112	1,140,296 **	8.37	10.5
R M SCHAHFER - UNIT 14	12-2021	60-R2 *	(11)	8,274,048.05	9,184,193	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	60-R2 *	(11)	14,130,188.82	15,684,510	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	60-R2 *	(11)	90,517,413.20	40,128,783	60,345,546	5,747,195 **	6.35	10.5
R M SCHAHFER - UNIT 18	12-2025	60-R2 *	(11)	96,892,278.80	43,225,441	64,324,988	6,126,189 **	6.32	10.5
SUGAR CREEK	06-2068	60-R2 *	(20)	57,667,038.75	7,987,309	61,213,138	1,633,121	2.83	37.5
TOTAL ACCOUNT 314				380,216,749.77	156,748,293	267,508,793	21,280,326	5.60	12.6
315.00 ACCESSORY ELECTRIC EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2026	65-R2 *	(8)	21,500,009.21	8,546,659	14,673,351	1,397,462 **	6.50	10.5
MICHIGAN CITY - UNIT 12	12-2026	65-R2 *	(8)	34,628,826.77	13,580,638	23,818,495	2,268,428 **	6.55	10.5
R M SCHAHFER GENERATING STATION	12-2025	65-R2 *	(11)	37,502,905.33	14,894,836	26,733,389	2,546,037 **	6.79	10.5
R M SCHAHFER - UNIT 14	12-2021	65-R2 *	(11)	9,152,749.82	10,159,552	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	65-R2 *	(11)	6,314,514.56	7,009,111	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	65-R2 *	(11)	61,137,859.51	27,246,983	40,616,041	3,868,194 **	6.33	10.5
R M SCHAHFER - UNIT 18	12-2025	65-R2 *	(11)	44,601,764.20	19,694,649	29,813,309	2,839,363 **	6.37	10.5
SUGAR CREEK	06-2068	65-R2 *	(20)	4,909,045.42	675,072	5,215,783	129,444	2.64	34.5
TOTAL ACCOUNT 315				219,747,674.82	101,807,500	140,870,368	13,048,928	5.94	10.8
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2026	70-R1.5 *	(8)	3,890,335.14	1,585,640	2,615,922	249,135 **	6.40	10.5
MICHIGAN CITY - UNIT 12	12-2026	70-R1.5 *	(8)	4,704,537.29	1,986,528	3,094,372	294,702 **	6.26	10.5
R M SCHAHFER GENERATING STATION	12-2025	70-R1.5 *	(11)	12,877,233.72	5,646,433	8,647,296	823,552 **	6.40	10.5
R M SCHAHFER - UNIT 14	12-2021	70-R1.5 *	(11)	981,904.75	1,089,914	0	0 **	-	10.5
R M SCHAHFER - UNIT 15	12-2021	70-R1.5 *	(11)	1,811,815.01	2,011,115	0	0 **	-	10.5
R M SCHAHFER - UNIT 17	12-2025	70-R1.5 *	(11)	6,188,369.28	2,960,268	3,908,822	372,269 **	6.02	10.5
R M SCHAHFER - UNIT 18	12-2025	70-R1.5 *	(11)	6,784,535.99	3,077,184	4,453,651	424,157 **	6.25	10.5
SUGAR CREEK	06-2068	70-R1.5 *	(20)	4,040,258.04	513,996	4,334,314	107,108	2.65	34.5
TOTAL ACCOUNT 316				41,278,989.22	18,871,078	27,054,377	2,270,923	5.50	11.9
TOTAL STEAM PRODUCTION PLANT				**2,606,488,067.59**	**1,071,360,263**	**1,810,220,456**	**160,159,732**	**6.14**	**11.3**
HYDRO PLANT									
331.00 STRUCTURES AND IMPROVEMENTS									
NORWAY GENERATING STATION	11-2037	70-S1 *	(8)	3,875,759.62	1,900,150	2,285,670	165,472	4.27	13.8
OAKDALE GENERATING STATION	11-2037	70-S1 *	(9)	7,088,825.05	3,699,663	4,027,156	291,896	4.12	13.8
TOTAL ACCOUNT 331				10,964,584.67	5,599,813	6,312,826	457,368	4.17	13.8
332.00 RESERVOIRS, DAMS AND WATERWAYS									
NORWAY GENERATING STATION	11-2037	85-R3 *	(6)	30,333,797.71	4,154,286	27,999,540	2,027,689	6.68	13.8
OAKDALE GENERATING STATION	11-2037	85-R3 *	(7)	18,896,329.12	3,286,661	16,932,411	1,227,369	6.50	13.8
TOTAL ACCOUNT 332				49,230,126.83	7,440,947	44,931,951	3,255,058	6.61	13.8
333.00 WATER WHEELS, TURBINES AND GENERATORS									
NORWAY GENERATING STATION	11-2037	75-R2 *	(6)	7,878,605.51	2,276,705	6,074,617	452,543	5.74	13.4
OAKDALE GENERATING STATION	11-2037	75-R2 *	(7)	6,495,122.48	2,345,036	4,604,745	339,831	5.23	13.6
TOTAL ACCOUNT 333				14,373,727.99	4,621,741	10,679,362	792,374	5.51	13.5

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
334.00 ACCESSORY ELECTRIC EQUIPMENT										
NORWAY GENERATING STATION	11-2037	55-L1.5	*	(6)	1,683,326.24	996,235	788,091	62,477	3.71	12.6
OAKDALE GENERATING STATION	11-2037	55-L1.5	*	(7)	839,479.23	325,734	572,509	43,145	5.14	13.3
TOTAL ACCOUNT 334					2,522,805.47	1,321,969	1,360,600	105,622	4.19	12.9
335.00 MISCELLANEOUS POWER PLANT EQUIPMENT										
NORWAY GENERATING STATION	11-2037	55-S0.5	*	(6)	712,410.12	279,407	475,748	35,660	5.01	13.3
OAKDALE GENERATING STATION	11-2037	55-S0.5	*	(7)	124,968.62	58,674	75,042	5,718	4.58	13.1
TOTAL ACCOUNT 335					837,378.74	338,081	550,790	41,378	4.94	13.3
TOTAL HYDRO PLANT					**77,928,623.70**	**19,322,551**	**63,835,529**	**4,651,800**	**5.97**	**13.7**
OTHER PRODUCTION PLANT										
341.00 STRUCTURES AND IMPROVEMENTS										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S2.5	*	(6)	2,756,354.53	2,362,772	558,964	186,341	6.76	3.0
SUGAR CREEK	06-2048	50-S2.5	*	(7)	12,225,886.59	5,515,752	7,565,947	331,992	2.72	22.8
TOTAL ACCOUNT 341					14,982,241.12	7,878,524	8,124,911	518,333	3.46	15.7
342.00 FUEL HOLDERS, PRODUCTS & ACCESSORIES										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S2.5	*	(3)	5,957,207.32	4,892,674	1,243,250	426,632	7.16	2.9
R M SCHAHFER - UNIT 16A	12-2026	50-S2.5	*	(3)	2,214,317.98	2,009,097	271,651	94,810	4.28	2.9
R M SCHAHFER - UNIT 16B	12-2026	50-S2.5	*	(3)	1,297,414.52	1,172,659	163,678	56,636	4.37	2.9
SUGAR CREEK	06-2048	50-S2.5	*	(7)	3,207,124.87	1,250,406	2,181,218	95,845	2.99	22.8
TOTAL ACCOUNT 342					12,676,064.69	9,324,836	3,859,797	673,923	5.32	5.7
343.00 PRIME MOVERS										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-R1	*	(3)	5,848,700.80	5,093,148	931,014	312,421	5.34	3.0
R M SCHAHFER - UNIT 16A	12-2026	50-R1	*	(3)	9,551,195.57	9,837,731	0	0	-	-
R M SCHAHFER - UNIT 16B	12-2026	50-R1	*	(3)	23,070,301.52	23,762,411	0	0	-	-
SUGAR CREEK	06-2048	50-R1	*	(7)	76,761,262.31	45,015,641	37,118,910	1,679,517	2.19	22.1
TOTAL ACCOUNT 343					115,231,460.20	83,708,931	38,049,924	1,991,938	1.73	19.1
344.00 GENERATORS										
R M SCHAHFER - UNIT 16A	12-2026	55-R3	*	(3)	6,625,784.57	6,750,067	74,491	24,830	0.37	3.0
R M SCHAHFER - UNIT 16B	12-2026	55-R3	*	(3)	2,538,171.36	2,614,317	0	0	-	-
SUGAR CREEK	06-2048	55-R3	*	(7)	40,547,004.58	22,021,609	21,363,686	916,140	2.26	23.3
TOTAL ACCOUNT 344					49,710,960.51	31,385,993	21,438,177	940,970	1.89	22.8
344.10 GENERATORS - SOLAR		20-S2.5		0	1,014,483.69	158,330	856,154	54,318	5.35	15.8
345.00 ACCESSORY ELECTRIC EQUIPMENT										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S1	*	(3)	18,757,510.34	12,325,414	6,994,822	2,331,607	12.43	3.0
R M SCHAHFER - UNIT 16A	12-2026	50-S1	*	(3)	759,938.06	782,736	0	0	-	-
R M SCHAHFER - UNIT 16B	12-2026	50-S1	*	(3)	1,308,789.12	1,146,136	201,917	67,492	5.16	3.0
SUGAR CREEK	06-2048	50-S1	*	(7)	34,611,832.01	16,241,859	20,792,801	962,059	2.78	21.6
TOTAL ACCOUNT 345					55,438,069.53	30,496,145	27,989,540	3,361,158	6.06	8.3
345.10 ACCESSORY ELECTRIC EQUIPMENT - SOLAR		20-S2.5		0	253,620.96	24,542	229,079	14,545	5.73	15.7
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-R2.5	*	(3)	533,483.87	415,811	133,677	44,695	8.38	3.0
SUGAR CREEK	06-2048	55-R2.5	*	(7)	5,645,982.05	2,628,663	3,412,538	147,133	2.61	23.2
TOTAL ACCOUNT 346					6,179,465.92	3,044,474	3,546,215	191,828	3.10	18.5
TOTAL OTHER PRODUCTION PLANT					**255,486,366.62**	**166,021,775**	**104,093,797**	**7,747,013**	**3.03**	**13.4**

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
TRANSMISSION PLANT									
350.20 LAND RIGHTS		75-R4	0	76,903,948.43	12,972,050	63,931,898	978,912	1.27	65.3
352.00 STRUCTURES AND IMPROVEMENTS		65-R1.5	(15)	88,052,012.25	34,893,524	66,366,290	1,197,600	1.36	55.4
353.00 STATION EQUIPMENT		52-S0	(10)	1,067,060,113.72	317,158,359	856,607,766	19,585,588	1.84	43.7
354.00 TOWERS AND FIXTURES		75-R4	(26)	168,314,495.66	88,418,562	123,657,703	2,114,910	1.26	58.5
355.00 POLES AND FIXTURES		62-R1	(35)	551,560,826.90	123,239,073	621,368,043	11,050,658	2.00	56.2
356.00 OVERHEAD CONDUCTORS AND DEVICES		68-R2	(40)	337,965,006.34	120,216,178	352,934,831	6,143,370	1.82	57.4
357.00 UNDERGROUND CONDUIT		65-S4	(5)	899,342.12	683,182	261,127	5,535	0.62	47.2
358.00 UNDERGROUND CONDUCTORS AND DEVICES		50-R1.5	(5)	3,852,252.26	1,141,758	2,903,107	69,101	1.79	42.0
359.00 ROADS AND TRAILS		70-R4	0	92,216.26	66,932	25,284	518	0.56	48.8
TOTAL TRANSMISSION PLANT				**2,294,700,213.94**	**698,789,618**	**2,088,056,049**	**41,146,192**	**1.79**	**50.7**
DISTRIBUTION PLANT									
360.20 LAND RIGHTS		75-R4	0	1,375,975.22	344,386	1,031,589	17,316	1.26	59.6
361.00 STRUCTURES AND IMPROVEMENTS		65-R1.5	(15)	16,828,466.07	9,240,468	10,112,268	207,264	1.23	48.8
362.00 STATION EQUIPMENT		50-R1.5	(10)	552,738,200.47	156,218,958	451,793,063	10,950,881	1.98	41.3
POLES, TOWERS AND FIXTURES									
364.10 CUSTOMER TRANSFORMER STATION		50-S0	(53)	56,866,138.03	35,150,210	51,854,981	1,257,621	2.21	41.2
364.20 POLES, TOWERS, AND FIXTURES		47-R1	(53)	615,333,057.72	236,009,428	705,450,150	17,833,830	2.90	39.6
TOTAL ACCOUNT 364				672,199,195.75	271,159,638	757,305,131	19,091,451	2.84	39.7
365.00 OVERHEAD CONDUCTORS AND DEVICES		65-R1	(60)	387,401,111.79	211,552,607	408,289,172	7,039,581	1.82	58.0
366.00 UNDERGROUND CONDUIT		70-S2.5	(5)	5,967,002.86	2,122,084	4,143,269	82,232	1.38	50.4
367.00 UNDERGROUND CONDUCTORS AND DEVICES		52-R2	(30)	588,030,774.37	186,422,843	578,017,164	13,515,573	2.30	42.8
368.00 LINE TRANSFORMERS		47-S0	(8)	377,676,754.42	147,885,750	260,005,145	7,044,886	1.87	36.9
SERVICES									
369.10 OVERHEAD SERVICES		47-R1	(32)	55,052,985.58	41,384,977	31,284,964	755,111	1.37	41.4
369.20 UNDERGROUND SERVICES		70-R3	(32)	279,915,670.17	145,725,175	223,763,510	3,726,848	1.33	60.0
TOTAL ACCOUNT 369				334,968,655.75	187,110,152	255,048,474	4,481,959	1.34	56.9
METERS									
370.10 CUSTOMER METERING STATIONS		50-R2	(2)	23,846,960.51	10,150,092	14,173,808	350,253	1.47	40.5
370.20 METERS		24-L0	(2)	75,930,087.87	27,902,929	49,545,761	2,674,608	3.52	18.5
TOTAL ACCOUNT 370				99,777,048.38	38,053,021	63,719,569	3,024,861	3.03	21.1
371.00 INSTALLATIONS ON CUSTOMER PREMISES		20-O1	(25)	10,463,918.32	6,950,349	6,129,549	371,739	3.55	16.5
373.00 STREET LIGHTING AND SIGNAL SYSTEMS		31-L0	(30)	64,108,114.54	28,551,926	54,788,623	2,146,236	3.35	25.5
TOTAL DISTRIBUTION PLANT				**3,111,535,217.94**	**1,245,612,182**	**2,850,383,016**	**67,973,979**	**2.18**	**41.9**
GENERAL PLANT									
390.00 STRUCTURES AND IMPROVEMENTS		55-R1.5	(10)	24,312,639.07	11,777,969	14,965,934	347,085	1.43	43.1
391.10 OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	4,764,626.59	2,893,068	1,871,559	181,862	3.82	10.3
391.20 COMPUTERS AND PERIPHERAL EQUIPMENT		7-SQ	0	21,803,108.62	12,136,913	9,666,196	3,397,605	15.58	2.8
393.00 STORES EQUIPMENT		30-SQ	0	984,845.25	696,376	288,469	14,420	1.46	20.0
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	28,427,977.49	10,606,283	17,821,694	1,087,549	3.83	16.4
395.00 LABORATORY EQUIPMENT		20-SQ	0	6,802,019.90	4,781,618	2,020,402	140,524	2.07	14.4
397.00 COMMUNICATION EQUIPMENT		15-SQ	0	38,827,784.66	7,867,197	30,960,588	3,382,628	8.71	9.2
398.00 MISCELLANEOUS EQUIPMENT		20-SQ	0	3,856,492.07	1,444,057	2,412,435	200,326	5.19	12.0
TOTAL GENERAL PLANT				**129,779,493.65**	**52,203,481**	**80,007,277**	**8,751,999**	**6.74**	**9.1**
ACCOUNT 391.2 RESERVE AMORTIZATION					9,600,000		(3,200,000)	***	3.0
TOTAL DEPRECIABLE ELECTRIC PLANT				**8,475,917,983.44**	**3,262,909,870**	**6,996,596,124**	**287,230,715**	**3.39**	**24.4**

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2023

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
NONDEPRECIABLE									
302.00 FRANCHISES AND CONSENTS				1,640.54	(33)				
303.00 MISCELLANEOUS INTANGIBLE PLANT				92,059,173.58	62,686,927				
310.00 LAND AND LAND RIGHTS				5,309,536.16	(21,577)				
311.00 STRUCTURES AND IMPROVEMENTS									
D H MITCHELL GENERATING STATION					4,481,692				
312.10 BOILER PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION					2,821,855				
312.30 BOILER PLANT - UNIT TRAIN COAL CARS									
BAILLY GENERATING STATION				2,701,500.27					
312.50 BOILER PLANT - COAL PILE BASE									
D H MITCHELL GENERATING STATION					69,620				
314.00 TURBO-GENERATOR UNITS									
D H MITCHELL GENERATING STATION					3,298,615				
315.00 ACCESSORY ELECTRIC EQUIPMENT									
D H MITCHELL GENERATING STATION					(2,570,344)				
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION					(1,224,757)				
330.00 LAND AND LAND RIGHTS				24,812.88	(221)				
340.20 LAND RIGHTS				1,126,899.78	(12,219)				
350.10 LAND				20,549,229.10	(180,923)				
360.10 LAND				4,102,199.55	(87,026)				
389.10 LAND				16,939.41	(12)				
389.20 LAND RIGHTS				120,527.51	(2,489)				
390.20 LEASED PROPERTY				252,224.97	156,664				
ACCOUNTS NOT STUDIED									
TRANSPORTATION EQUIPMENT									
392.20 TRANSPORTATION EQUIPMENT - TRAILERS				1,675,172.99	902,824				
392.30 TRANSPORTATION EQUIPMENT - TRUCKS < 13,000				388,177.16	39,318				
392.40 TRANSPORTATION EQUIPMENT - TRUCKS > 13,000				454,874.49	786,940				
396.00 POWER OPERATED EQUIPMENT				6,093,725.82	4,902,444				
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED				134,876,634.23	76,047,298				
TOTAL ELECTRIC PLANT				8,610,794,617.67	3,338,957,168				

* INTERIM SURVIVOR CURVES USED. EACH LOCATION HAS A UNIQUE PROBABLE RETIREMENT DATE.

** ANNUAL ACCRUAL AMOUNT IS BASED ON 11 YEAR REMAINING LIFE.

*** SEPARATE RESERVE AMORTIZATION TO BE RECOVERED OVER 5 YEARS BEGINNING IN 2021.

STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831/531 MODIFICATION

This Stipulation and Settlement Agreement on Rate 831/531 Modification (the "Agreement")[1] is entered into this 12th day of September, 2022, by and among Northern Indiana Public Service Company LLC ("NIPSCO") and the NIPSCO Industrial Group;[2] NLMK Indiana; Pratt Paper (IN), LLC; and United States Steel Corporation (collectively the "Rate 831 Customers," and with NIPSCO, the "Rate 831 Settling Parties"), who stipulate and agree for purposes of settling issues related to Rate 831 to be presented in NIPSCO's forthcoming general rate case proceeding, that the terms and conditions set forth below represent a fair and reasonable resolution of all issues related to the Rate 831 Settling Parties' modification of Rate 831 in the electric rate case proceeding NIPSCO intends to file in September of 2022, subject to the terms of Section B.6.

This Agreement sets forth NIPSCO's modified Alternative Regulatory Plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 for Rate 831 Modification, which NIPSCO intends to file as part of its case-in-chief in its upcoming rate proceeding. The Rate

---

1 The current NIPSCO electric tariff rate schedule under which the customers who are signatories to this Agreement currently take service is Rate 831. The successor rate schedule proposed by NIPSCO in the forthcoming base rate case proceeding will be designated Rate 531. For sake of clarity, throughout this Agreement, "Rate 831" and "Rate 831 customers" is used consistently throughout to refer to both the current and proposed tariff rate and customers, except where necessary to distinguish between the current Rate 831 and the proposed Rate 531.

2 For purposes of this Agreement, the NIPSCO Industrial Group is comprised of Cleveland-Cliffs Steel LLC, Linde, Inc., BP Products North America, Inc., and Cargill, Inc.

Confidential - Excluded from public access per A.R. 9(G)

831 Settling Parties stipulate and agree to NIPSCO's modified ARP and agree to file testimony in the upcoming rate proceeding or otherwise affirmatively support the ARP and the terms of this Agreement. The terms and obligations set forth in this Agreement are conditioned on approval of the ARP and incorporation of this Agreement into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without material modification, change or conditioning term that is unacceptable to any of the Rate 831 Settling Parties at the conclusion of the rate proceeding.

A. Background

WHEREAS, NIPSCO filed a Verified Petition initiating Cause No. 45159 on October 31, 2018 requesting, among other relief, approval of an ARP pursuant to Indiana Code § 8-1-2.5-6 that would facilitate a new service structure for industrial rates (Rate 831) to address a changing energy landscape;

WHEREAS, in Cause No. 45159, NIPSCO filed testimony explaining the operation of Rate 831 and supporting the need for Rate 831 to address the loss of industrial load, provide a more competitive rate structure for large industrial customers, and promote effective system planning as NIPSCO transitions its generation resources;

WHEREAS, in Cause No. 45159, NIPSCO and prospective Rate 831 customers reached a mutual agreement on issues related to Rate 831 (collectively, the "45159

Confidential - Excluded from public access per A.R. 9(G)

Rate 831 Settling Parties") and such agreement was memorialized in a Stipulation and Settlement Agreement filed with the Commission on May 17, 2019 (the "831 Implementation Agreement"). The 831 Implementation Agreement was ultimately approved by the Commission in its Final Order dated December 4, 2019. The 831 Implementation Agreement and supporting testimony also called for approval of the cost of service study and allocation methodology presented by NIPSCO, as modified on rebuttal;

WHEREAS, in Cause No. 45159, the Commission approved the allocation of production costs using the 4 Coincident Peak ("4 CP") method, consistent with NIPSCO's system load characteristics and the design and operation of NIPSCO's system;

WHEREAS, under the terms of Rule 5.8 of NIPSCO's electric tariff as approved by the Commission in Cause No. 45159, the existing Rate 831 service contracts would terminate upon the approval of new base rates, and upon such termination all Rate 831 customers could potentially reduce their level of Tier 1 firm contract demand down to the tariff minimum of 10 MW each, or 70 MW in total;

WHEREAS, in order to reduce the contested issues in NIPSCO's upcoming rate proceeding, the Rate 831 Settling Parties negotiated in advance of NIPSCO's filing and have reached mutual agreement on issues related to Rate 831 (which will be renumbered Rate 531) for purposes of that cause. The Settling Parties' agreement

Confidential - Excluded from public access per A.R. 9(G)

with respect to the Rate 831 issues to be presented in that cause is set forth in this Agreement, and it is the intent of the Rate 831 Settling Parties to file testimony supporting this Agreement as part of NIPSCO's upcoming rate proceeding; and

WHEREAS, the Rate 831 Settling Parties request Commission approval of NIPSCO's modified ARP and this Agreement in its entirety, without material change or modification unacceptable to any of the Rate 831 Settling Parties, and incorporation of this Agreement in its Final Order in NIPSCO's upcoming rate proceeding;

NOW, THEREFORE, the Rate 831 Settling Parties agree to the following:

B. Settlement Terms

1. Scope of this Agreement:

The scope of this Agreement is limited to the Rate 831 Settling Parties' mutual agreement and understanding with respect to the modification of NIPSCO's ARP to reflect changes in allocation of costs between Rate 831 and Rate 531, including the use and approval of a 4 CP cost of service methodology for the allocation of production demand-related costs and a 12 CP cost of service methodology for the allocation of transmission demand-related cost, the agreed level of Tier 1 contract demand by the Rate 831 customers, the resulting design of rates for new Rate 531, and those other items expressly

Confidential - Excluded from public access per A.R. 9(G)

stated herein. Except as expressly stated herein, this Agreement does not provide for any further modifications to NIPSCO's ARP approved in Cause No. 45159 nor modifications to the existing Rate 831 tariff. The Rate 831 Settling Parties reserve all rights with respect to issues and positions not addressed in this Agreement, including, but not limited to, NIPSCO's revenue requirement, NIPSCO's proposals for modifications to the new Rate 531 tariff set forth in Section B.6. of this Agreement, non-Rate 831 or 531 specific rate proposals, and adjustments to NIPSCO's as-filed allocated cost of service study, provided that any such proposed adjustments to the allocated cost of service study do not propose alteration of the use of the 4 CP demand related production or 12 CP demand related transmission allocation methodologies.

2. Allocation:

a. The Rate 831 Settling Parties agree that NIPSCO's allocated cost of service methodology to be filed in the upcoming rate proceeding will be based upon the 4 CP method for production demand-related costs.[3] The Rate 831 Settling Parties agree that

[3] The 4 CP methodology uses the summer months of June, July, August and September to calculate the coincident peak demand allocation factors for purposes of allocating demand-related costs associated with production functions.

Confidential - Excluded from public access per A.R. 9(G)

the 4 CP cost of service study should be used to allocate costs to Rate 831 as a class based on a Rate 831 Tier 1 subscription of 180 megawatts. Each of the Rate 831 Customers agrees to execute a new contract for Tier 1 demand subscription under Rate 831 as set forth in Confidential Attachment A to this Agreement for the contract term set forth in Section B.3.a. of this Agreement. The production demand-related cost of service shall be allocated to Rate 831 using 180 megawatts, and rates shall be designed for Rate 831 using the contracted Tier 1 demand levels totaling 170 megawatts. The Rate 831 Settling Parties agree to the allocation of tracker costs to Rate 831 Customers as set forth in Attachment B to this Agreement and further agree that only Rate 831/531 Customers' Tier 1 commitments constitute "firm load" for purposes of any transmission, distribution, and storage system improvement charge ("TDSIC") expenditures and costs, and that the TDSIC revenue allocation shall be applied only to revenue associated with Rate 831 Customers' Tier 1 contract demand.

b. The 831 Settling Parties recognize and understand that the Tier 1 contract demands as set forth in Section B.2.a. of this

Confidential - Excluded from public access per A.R. 9(G)

Agreement will be binding only through the end of the Contract Term as set forth below. This Agreement does not bind the Rate 831 Customers beyond that term, and NIPSCO's new Rate 531 tariff and rules will be adjusted to reflect such term.

c. As part of the agreement to allocate 180 megawatts of production demand related costs to Rate 831 and the Tier 1 contract demand commitments established for purposes of the upcoming rate proceeding, the Rate 831 Customers shall retain future flexibility to adjust Tier 1 levels consistent with the terms of the existing tariff. For purposes of the upcoming rate proceeding, the 831 Settling Parties recognize that the agreed demand level for cost allocation purposes exceeds the committed level of actual contract demand, and that this approach allocates costs to the Rate 831 class in excess of the cost of service based on Tier 1 commitments but moves the overall allocation closer to cost of service than is provided under current rates. The Rate 831 Settling Parties agree that in future rate proceedings the cost allocation to Rate 831 (and any successor rate) will continue to move the class toward the actual cost of service based on actual contract demands.

Confidential - Excluded from public access per A.R. 9(G)

d. Prior to the earlier of the commencement of a future rate case or the contract termination date, NIPSCO and Rate 831 Customers agree to meet and negotiate in good faith to establish new class demand allocation and Tier 1 contract demand levels for the subsequent period, recognizing that further reductions in both the class allocation and Tier 1 commitments will be expected at that time.

3. Contract Term:

a. Existing Rate 831 Customers. With respect to existing Rate 831 Customers, the expiration of the term of any contract entered into for purposes of receiving service under the new Rate 531 shall be the earlier of: (1) the effective date for new rates under NIPSCO's next electric rate case filing after the rate case to be filed in September of 2022; or (2) May 31, 2026. The commitments set forth in this Agreement and any contract entered into for purposes of receiving service under the new Rate 531 shall be binding only through the end of the Contract Term.

b. Rate 831 Increases in Tier 1 Demand. Any existing Rate 831 customer, or new Rate 531 customer, may increase Tier 1 firm

Confidential - Excluded from public access per A.R. 9(G)

contract demand or begin taking service under new Rate 531 in accordance with the existing Rate 831 tariff terms.

4. Tracker Allocations:

a. The Rate 831 Settling Parties agree that allocation factors for NIPSCO's existing and proposed tracker mechanisms shall be developed in a manner consistent with Exhibit A to the 831 Implementation Agreement as modified by this Agreement, the cost of service methodology and rate design as agreed herein, and the revenue requirement as approved by the Commission.

b. The Rate 831 Settling Parties agree that the Rate 831/531 Modification – Exhibit B, attached hereto, sets out the applicable portions of Rate 531 that are subject to each existing tracker mechanism.

c. For the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that the allocation factors for TDSIC purposes shall be developed in a manner consistent with Exhibit A to the 831 Implementation

Confidential - Excluded from public access per A.R. 9(G)

Agreement as modified by this Agreement, the cost of service methodology and rate design as agreed herein, and the revenue requirement as approved by the Commission.

5. Rate 831 Rate Design:

a. Except as otherwise provided herein, the Rate 831 Settling Parties agree that Rate 831 shall be modified and adopted as proposed in NIPSCO's ARP as set forth in this Agreement and based on the revenue requirement that is ultimately approved in the upcoming rate case to be filed by NIPSCO.

b. The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the 4 CP method for production–related demand cost of service methodology. The Tier 1 demand commitments set forth in Rate 831/531 Modification - Confidential Exhibit A are contingent on approval of said cost of service study, and absent such approval shall not be binding on Rate 831 customers.

c. For purposes of transmission demand-related costs, the Rate 831 Settling Parties agree that the design of Rate 831 should be based on the 12 CP cost of service methodology to be presented by NIPSCO in its case-in-chief filed in its upcoming rate case.

Confidential - Excluded from public access per A.R. 9(G)

d. For purposes of the "Adjacent Affiliate Qualified Facility Premise Transmission Charge," the Rate 831 Settling Parties agree that the terms of the existing Rate 831 tariff shall remain in effect.

e. The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the existing Rate 831 customers and their corresponding Rate 831 Tier 1 energy is set forth in Rate 831/531 Modification – Confidential Exhibit A, attached hereto. The Rate 831 Settling Parties agree that the Tier 1 subscriptions reflected in Rate 831/531 Modification – Confidential Exhibit A shall be binding upon each customer for the contract term, except as provided for in this Agreement and under the terms of NIPSCO's electric tariff.

6. Tariff Language:

The Rate 831 Settling Parties agree that the terms of this Agreement do not require any change or modification to the existing provisions of the Rate 831 tariff, except as expressly provided herein. NIPSCO has discussed two potential changes to existing Rate 831 beyond those presented in this Agreement, which relate to good faith efforts to provide updated load forecasts and potential modifications to

Confidential - Excluded from public access per A.R. 9(G)

reference MISO's proposed seasonal resource adequacy construct. However, as set forth in Section B.1. above, those provisions are outside the scope of this Agreement. Therefore, NIPSCO reserves the right to propose changes consistent with these two items, and the Rate 831 Settling Parties reserve the right to take any position with respect to these two items, and only these two items. In all other respects, the terms and provisions of the Rate 831 tariff shall be maintained intact in the new Rate 531, except as described herein.

C. Procedural Aspects and Presentation of the Agreement

1. The Rate 831 Settling Parties have spent considerable and valuable time reviewing data and negotiating the Agreement in an effort to resolve potentially contested issues in NIPSCO's upcoming rate case and to avoid time consuming and costly litigation. The Rate 831 Settling Parties will request that the Commission review this Agreement as part of NIPSCO's modification of its ARP in the upcoming rate case, and approve said modification to the ARP and incorporate the terms of this Agreement into its Final Order issued in that cause, in its entirety and without material modification or condition unacceptable to any of the Rate 831 Settling Parties. To the extent the Commission makes material change or modification to this Agreement that is unacceptable to one or more of the Rate 831 Settling Parties, or otherwise does not approve this Agreement, the Rate 831 Settling Parties acknowledge that NIPSCO will be

Confidential - Excluded from public access per A.R. 9(G)

required to make a subsequent filing consistent with the Commission's Final Order before it can implement rates for any customer class. In the event such an order includes a material change or modification, each of the Rate 831 Settling Parties shall notify all other Rate 831 Settling Parties in writing within 5 days of issuance whether such change or modification is acceptable. Further, if an order does not approve this Agreement or makes an unacceptable change or modification, and absent further agreement among the Rate 831 Settling Parties to the contrary, each of the Rate 831 customers shall, within 10 days of issuance, provide to NIPSCO in writing (a) their new level of Tier 1 firm demand, which shall be no less than 10 megawatts, or (b) for any Rate 831 customer who chooses to take service under any other rate schedule, the rate schedule under which they are electing to take service. The Rate 831 Settling Parties shall also proceed promptly with good faith negotiations in accordance with Section C.3. NIPSCO shall retain all rights and options available by law with respect to compliance filings or other measures associated with the implementation of approved rates, and each of the Rate 831 Settling Parties shall retain all rights and options available by law to seek rehearing, commence an appeal or otherwise pursue relief relating to such order.

a. For purposes of this Agreement, a material modification includes, but is not limited to, a modification to (i) production demand-related cost

Confidential - Excluded from public access per A.R. 9(G)

of service using 180 megawatts or rates designed using the contracted Tier 1 demand levels totaling 170 megawatts; (ii) the agreed-to contract term; (iii) 4 CP cost of service methodology for production-related demand-related cost; and (iv) 12 CP cost of service methodology for the allocation of transmission demand-related cost.

2. The Rate 831 Settling Parties agree to assist and cooperate in the preparation and presentation of testimony in support of NIPSCO's proposed ARP and this Agreement, in order to provide an appropriate factual basis for the Commission to implement NIPSCO's modified ARP and this Agreement into its Final Order.

3. The concurrence of the Rate 831 Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's continued approval of the 4 CP methodology for the allocation of production demand-related costs and 12 CP methodology for the allocation of transmission demand-related costs as set forth in NIPSCO's allocated cost of service study to be filed in its upcoming rate case. In the event the 4 CP methodology for purposes of allocating production demand-related costs or the 12 CP methodology for purposes of allocating transmission demand-related costs is not approved by Commission, or any other material modification is made to this Agreement that is unacceptable to one or more of the Rate 831 Settling Parties, the Rate 831 Settling Parties agree to meet promptly and to negotiate in good faith to reach a new agreement determining the

Confidential - Excluded from public access per A.R. 9(G)

allocation and contractual demand for such purposes, or otherwise revising the structure, design or terms of the rate schedule or schedules under which Rate 831 customers take service, and shall submit such agreement to the Commission within thirty (30) days of the date of the Commission Order.

4. The Rate 831 Settling Parties agree that this Agreement and each term, condition, amount, methodology, and exclusion contained herein reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. Except as expressly discussed herein, the Rate 831 Settling Parties agree that a Final Order approving this Agreement shall not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise and each of the Rate 831 Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense. If the terms of this Agreement are not approved by the Commission as part of its Final Order, the Rate 831 Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding.

Confidential - Excluded from public access per A.R. 9(G)

5. The Rate 831 Settling Parties stipulate that the evidence of record to be presented in NIPSCO's upcoming rate case will constitute substantial evidence sufficient to support the modification to NIPSCO's ARP and this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for incorporation of this Agreement into the Commission's Final Order. The Rate 831 Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

6. The Rate 831 Settling Parties shall not appeal the Final Order or any subsequent Commission order as to any portion of such order that is specifically approving or implementing the provisions of this Agreement and NIPSCO's modified ARP without material modification or condition unacceptable to any of the Rate 831 Settling Parties; and the Rate 831 Settling Parties shall oppose any appeal of any portion of the Final Order approving this Agreement and NIPSCO's modified ARP.

7. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Rate 831 Settling Party has had the opportunity to review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

Confidential - Excluded from public access per A.R. 9(G)

8. The provisions of this Agreement shall be enforceable by any Rate 831 Settling Party before the Commission or in any court of competent jurisdiction.

9. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 12th day of September, 2022.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC



Confidential - Excluded from public access per A.R. 9(G)

NIPSCO Industrial Group



Confidential - Excluded from public access per A.R. 9(G)

NLMK INDIANA

Nicholas Thomas 9.9.22

Confidential - Excluded from public access per A.R. 9(G)

United States Steel Corporation

Kristina Kern Wheeler

Pratt Paper (IN), LLC



Stephen Ward
Chief Financial Officer

Northern Indiana Public Service Company LLC
Modification Agreement Confidential Exhibit A

Customer	Contract Demand (MW)
[redacted]	
Total	170.0

Rate 831/531 Modification Agreement Exhibit B

Confidential - Excluded from public access per A.R. 9(G)

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 15
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 570	FAC	Adjustment of Charges for Cost of Fuel Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 571	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1 and Tier 2, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 574	RA	Adjustment of Charges for Resource Adequacy	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 576	BMTIS	Back-Up and Maintenance Industrial Service Rider	531
Rider 577	EDR	Economic Development Rider	524, 526, 532, 533
Rider 578	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541, 544,
Rider 579	IS	Interconnection Standards	511, 520, 521, 522, 523, 524, 525, 526, 531, 532, 533, 541, 544, 565
Rider 580	NM	Net Metering	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541

Confidential - Excluded from public access per A.R. 9(G)
NIPSCO

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 15
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 581	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 582	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 583	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, 544, Rider 576
Rider 586	GPR	Green Power Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, and Rider 576
Rider 587	FMCA	Adjustment of Charges for Federally Mandated Costs	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 588	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 589	EDG	Excess Distributed Generation	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541
Rider 594		Adjustment of Charges for Variable Costs of Coal-Fired Generation	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 597		Universal Service Program (USP) Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576

Confidential - Excluded from public access per A.R. 9(G)
NIPSCO

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 105
DOE Order No. 202-08-1

The Secretary of Energy
Washington, DC 20585

Order No. 202-08-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Ike, large portions of the areas affected by the hurricane are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, CenterPoint Energy is authorized and directed to temporarily connect at distribution and transmission level voltages such as 12.5kV, 13.2kV, 25kV, 69kV, 138kV, and 230kV to restore power to Entergy Gulf States, Inc. as well as electric cooperatives and municipal customers within the State of Texas. Pursuant to section 202(d) of the FPA, 16 U.S.C. 824a(d), during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may, pursuant to this order, make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2008.

Issued in Washington, D.C. at 1600 this 14th day of September, 2008.

Samuel W. Bodman
Secretary of Energy

Printed on recycled paper