Department of Energy
Washington, DC 20585

Consumers Energy Company and
Midcontinent Independent System Operator, Inc.
Regarding J.H. Campbell Generating Plant

Order No. 202-26-39

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midcontinent Independent System Operator, Inc. (MISO) region due to a sudden increase in demand or a shortage of electric energy or facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, November 19, 2025, February 17, 2026, May 18, 2026, and August 16, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the region served by MISO.

Specifically, I determined that MISO likely faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[4] I determined that the continued operation of the Campbell Plant would provide additional generation capacity during

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] *See* Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation* (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation.

[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, DOE Order No. 202-25-9, at 1 (Nov. 18, 2025).

these periods, which would help prevent the potential loss of power to homes and businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[5] I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.[6]

My determination was based on a number of facts. First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[7] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[8]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[9] Additionally, EIA stated, "Michigan's nuclear power plants typically supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[10] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although the plant will reportedly resume service in 2026.[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural

---

[5] *Id.* at 5; *see also id.* at 1, 8.

[6] *Id.* at 1.

[7] N. Am. Elec. Reliability Corp., *2025 Summer Reliability Assessment*, at 16 (May 2025), https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf.

[8] *Id*.

[9] EIA, *Mich. State Profile & Energy Estimates* (Nov. 19, 2025), https://www.eia.gov/states/MI/analysis.

[10] *Id*.

[11] *See* Dustin Dwyer, *Palisades nuclear plant restart plans pushed back to "early 2026,"* MICH. PUB. (Dec. 17, 2025), https://www.michiganpublic.org/environment-climate-change/2025-12-17/palisades-nuclear-plant-restart-plans-pushed-back-to-early-2026; Will Wade, *Despite $80-billion commitment, nuclear plants face decadelong timeline to meet AI energy needs*, L.A. TIMES (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

gas power plant in Covert, Michigan, NERC has noted that "[e]scalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area."[12]

Fourth, MISO's Planning Resource Auction Results for the 2026–2027 Planning Year, released in April 2026, notes that "capacity additions need to continue, given expected growth from new large loads."[13] Further, MISO reiterates that "while our market reforms have helped hold the line amidst tighter reserve margin compared to the prior decade, resource adequacy remains at risk, especially as demand for large load additions accelerate."[14]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22 continue, both in the near and long term.[15] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the EIA-923 Power Plant Operations Report's monthly generation data for May 2026, the total net generation for the Campbell Plant was 1,431,336 MWh from January 2026 to May 2026 for an average of 286,267 MWh per month.[16] The historic data of consistent generation indicates the Campbell plant is providing vital generation capacity to the region. From June 11, 2025, through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its

[12] NERC, *2025 Long-Term Reliability Assessment*, at 15 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter NERC *LTRA*].

[13] MISO, *Planning Res. Auction Results for Planning Year 2026/27*, at 3 (Apr. 2026) (Updated May 22, 2026) (MISO 2026–2027 Planning Resource Auction), https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf.

[14] *Id.* at 7.

[15] It likely would be difficult for a coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Consumers was to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[16] *See* EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920)*, https://www.eia.gov/electricity/data/eia923/ (choose "2026: EIA-923 May 2026").

Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.[17]

MISO's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[18]

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[19] MISO justified this revision by explaining that "[r]eliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[20] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[21]

In December 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[22] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.[23] MISO also projected that the risk of loss of load in the winter

---

[17] MISO, *Operations Rep.* (Sept. 16, 2025), https://cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report717458.pdf.

[18] MISO, *Operations Rep.*, at 10 (Mar. 24, 2026), https://cdn.misoenergy.org/20260324%20Markets%20Committee%20of%20the%20BOD%20Item%2008%20MISO%20Operations%20Report746763.pdf.

[19] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, Docket No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[20] MISO Transmittal Letter at 3.

[21] *Id.* at 3–4.

[22] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[23] *Id.* at 11.

and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[24]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.[25] In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[26]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

Further, in January 2026, NERC released its 2025 Long-Term Reliability Assessment (LTRA).[27] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[28] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[29] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[30] Moreover, the 2025 NERC LTRA notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[31] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[32] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[33]

The 2025–2026 NERC Winter Reliability Assessment (WRA) found the MISO region to be at normal risk in 2026 and elevated risk in 2027. The two previous winter

---

[24] *Id.*

[25] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[26] *Id.* at 12.

[27] *See* NERC *LTRA*, *supra* note 12.

[28] *Id.* at 6, 8.

[29] *Id.* at 8.

[30] *Id.* at 43.

[31] *Id.* at 15.

[32] *Id*.

[33] *Id*.

studies respectively characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions"[34] and noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[35]

NERC released its 2026 Summer Reliability Assessment (SRA) on May 19, 2026. In its assessment, NERC stated that "MISO's peak load has increased by 2.5 GW from the 2025 SRA."[36] The 2026 SRA also projects that data center load will continue to accelerate in 2027 and beyond, potentially increasing reliability risk if capacity additions do not keep pace.[37] Furthermore, the 2026 SRA states that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations . . . and EEAs."[38]

There continues to be tight capacity available during summer despite the recent "gains in offered capacity outpacing pressure of load growth" in the MISO region, as reported in its PRA for the 2026-2027 Planning Year.[39] MISO noted that "new generation capacity is coming online, but faster resource additions are still needed to support large-load growth and ensure resource adequacy."[40]

On June 4, 2026, the Organization of MISO States (OMS) and MISO issued the results of their 2026 survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[41] The 2026 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years and states "growth as submitted by [load serving entities or LSEs] continues to accelerate, with a [compound annual growth rate or CAGR] projected between 3.1% and 5.1% over [the next] five years."[42]

The OMS-MISO Survey further indicates that "[v]arious projected capacity scenarios and large load additions highlight increasing uncertainty and evolving risk"[43]

---

[34] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[35] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[36] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[37] *Id.*

[38] *Id*.

[39] MISO 2026–2027 Planning Resource Auction at 3.

[40] *Id.* at 2.

[41] OMS & MISO, *OMS-MISO Survey Results* (updated June 4, 2026) (2026 OMS-MISO Survey), https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf.

[42] *Id.* at 2.

[43] *Id.* at 3.

and observes various negative risks. Examples include intensification of winter reliability risks based on resource availability/performance, which exacerbates seasonal reliability vulnerabilities; delay of new resource deployment owing to persistent supply-chain disruptions, labor constraints and permitting challenges; resource adequacy pressures continuing from load growth driven by data centers, new industrial, and commercial development; and continued backlog and uncertainty related to resources with signed Generator Interconnection Agreements (GIA).[44] In addition, 87 GW of signed GIAs are not yet online, and 192 GW of active GIAs still under study.[45]

Finally, the OMS-MISO Survey lists ongoing challenges such as more frequent extreme weather; accelerating demand for electricity and large load interconnections; loss of accredited capacity and reliability attributes as resource mixes evolve; the increasing pace of new resources additions; addressing local reliability issues (load pocket); and evolving storage participation.[46]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for Bulk Power System operators to manage, resulting in several recent instances of pre-contingent load shedding."[47] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[48] Finally, data in the SOR shows that 2025 MISO summer and winter peak demands of 121.6 GW and 108.8 GW, respectively, met or exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a real risk in MISO.[49]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an 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. This proposal was approved by FERC on July 21, 2025.[50] MISO's ERAS should help expedite the construction of needed new capacity; however, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial

---

[44] *Id.* at 4.

[45] *Id.*

[46] *Id.* at 16.

[47] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[48] *Id.* at vii.

[49] *Id.* at 28, 30.

[50] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

operations.[51] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[52] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that 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."[53] The Executive Order adds, "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."[54] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "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 increase in domestic manufacturing."[55]

In addition, President Trump issued a White House Memo to the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . [w]ithout sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as

---

[51] NERC, *State of Reliability*, *supra* note 48, at 84.

[52] *See generally* Jared Anderson, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P GLOBAL (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

[53] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[54] *Id*.

[55] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

artificial intelligence."[56] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[57]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent 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."[58] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[59] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[60]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, MISO's Senior Vice President for Planning and Operations, Jennifer Curran, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[61] Ms. Curran also described "much stronger growth [in demand

---

[56] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) ("Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity"), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[57] *Id.*

[58] U.S. Dep't of Energy, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[59] Ekku Jokinen, *Top 21 A.I. Cos. in Mich.* , INVEN (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[60] *See* Zachary Skidmore, *Mich. util. Consumers Energy to provide 1GW of power to new hyperscale data center*, DATA CENTER DYNAMICS (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/.

[61] *Keeping the Lights On: Examining the State of Regional Grid Reliability; Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President

for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[62] She added, "A growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[63]

Pursuant to section 202(c)(4)(B) of the FPA, DOE has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[64] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such operation will best meet an emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of the Campbell Plant will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and to serve the public interest under FPA section 202(c), the Campbell Plant shall be made available for operation through November 14, 2026.[65]

---

for Planning and Operations, MISO), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[62] *Id.* at 6.

[63] *Id.* at 7.

[64] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[65] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 17, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with this Order.

C. All operations of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By August 31, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective on August 17, 2026, through November 14, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 14th day of August 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc:

Federal Energy Regulatory Commission
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commission
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-3

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202 (c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and petition for rehearing of the Department of Energy's ("DOE") May 23, 2025, Order No. 202-25-3 ("Order," Exhibit 1) directing the Midcontinent Independent System Operator ("MISO") to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan, operated by Consumers Energy, remains available to operate through August 20, 2025, expiring at 00:00h on August 21, 2025.

Pursuant to the Federal Power Act ("the Act") and Department procedures applying it to petitions for rehearing, the States hereby file this timely request for rehearing of DOE's Order. The Order proceeds from a faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO")—specifically for the summer months of 2025. This Order exceeds DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to meet the purported need. It should be rescinded.

TABLE OF CONTENTS

Motion to Intervene 3

Petition for Rehearing 8

I. Overview and Concise Statement of Error 8

II. Legal Background 12

III. Statement of Issues 13

IV. Description of MISO 16

V. Argument 18

A. The Order lacks substantial evidence demonstrating the existence of an actual emergency and DOE failed to engage in reasoned decision-making. 18

B. The Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371. 22

C. The Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1). 26

D. The Order exceeds DOE's authority because it does not set any hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3). 26

E. The Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states. 27

F. The Order impermissibly calls for state governments to assist in its execution. 31

G. The Order is unreasoned, arbitrary, and capricious because the actions it mandates will not meet the purported emergency. 32

Conclusion 35

MOTION TO INTERVENE

The States[1] move to intervene in this proceeding and thereby to become a party for purposes of Section 313l of the Act, 16 U.S.C. § 825l. The States have an interest in and are aggrieved by the Order in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U. S. ___ (2025) (slip op., at 3–8) (defining an "adversely affected or aggrieved" party within the APA and without as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Association of Data Processing Service Organizations, Inc. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities in the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator ("ISO") in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the "air traffic controller" for the grid in its territory[2], meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

---

[1] *See* Minn. Stat. § 8.01 ("The attorney general shall appear for the state in all causes in the supreme and federal courts wherein the state is directly interested; also in all civil causes of like nature in all other courts of the state whenever, in the attorney general's opinion, the interests of the state require it.).

[2] "Meet MISO," https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/what-we-do/ (last visited June 23, 2025).

On May 23, 2025, the DOE issued an emergency order pursuant to section 202(c) of the Federal Power Act to MISO. *See* Ex. 1; *see also* 16 U.S.C. § 824(c)(1). The Order directs MISO, in coordination with Consumers Energy, the owner of the plant, to ensure that the Campbell Plant in West Olive, Michigan remains available for operation. *Id.* Consumers Energy announced its plan to retire the coal facility in 2021, and MISO approved that plan three years ago, in March 2022.[3]

Adverse Effects

The States will be adversely affected by the emergency order preventing the planned retirement of the Campbell Plant in two primary ways.

First, households and businesses in the States, and the States as consumers in their own right, all will pay higher electricity bills as a result of the Order's imposition of costs and cost-recovery to the States. By ordering the Campbell Plant to take all steps necessary to be available and ordering MISO to take all steps necessary for the Campbell Plant to provide economic dispatch, costs are already being incurred and more costs will continue to be generated. Notably, the age of the units is concerning for costs, and Consumers Energy projected in 2021 that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs.[4] The Order would likely require at least a portion of capital expenditures and major maintenance costs that were not completed in the last four years, which will potentially drive up

---

[3] *See* Consumers Energy, "2021 Clean Energy Plan," https://www.consumersenergy.com/-/media/CE/Documents/company/IRP-2021.pdf (last accessed June 23, 2025).

[4] *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, MPSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala on Behalf of Consumers Energy Company at 3 (Oct. 2021).

costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Order provides that cost recovery is available to Consumers Energy through Federal Energy Regulatory Commission ("FERC") proceedings, which Consumers Energy has already initiated. Consumers Energy filed a petition FERC[5] asking for a process to allocate costs (net of market revenues) across all of MISO Zones 1 through 7 (which includes Minnesota and Illinois). They ask that costs be apportioned according to load, which would assign costs to the States. MISO has already filed its answer indicating its general support for adjusting its tariff to account for Consumers Energy's cost recovery petition, meaning the costs would be charged to the States according to their respective share of load.

Second, the States will suffer environmental harms as a result of the Order. The Campbell Plant is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[6] among other pollutants. By prolonging the operations of the Campbell Plant beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan and other MISO States, causing harm to the public health and welfare.[7] Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States, imposes significant additional costs on them for responsive actions and resiliency programs, and threatens state climate goals and comply with federal and state air pollution requirements.

---

[5] FERC Docket: EL25-90.

[6] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

[7] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.[8] Each of Minnesota's top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.[9] Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.[10] These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.[11] Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures. The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal declarations for large parts of the state.[12] From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.[13] The "Lost Winter" of 2023-2024 was the

---

[8] Minnesota Climate Trends, *Minnesota Department of Natural Resources* (2023), https://www.dnr.state.mn.us/climate/climate_change_info/climate-trends.html.
[9] *Id*.
[10] *Id*.
[11] *Id*.
[12] "Extreme Rainfall Drenches Northeastern Minnesota," Minnesota Department of Natural Resources, https://www.dnr.state.mn.us/climate/journal/extreme-rainfall-northeast-mn-june-18-2024; "Extreme Rain and Flooding in Southern Minnesota, June 20-22," Minnesota Department of Natural Resources, (August 9, 2024), https://www.dnr.state.mn.us/climate/journal/extreme-rain-flooding-southern-minnesota-june-20-22.html; "Disaster information," Minnesota Department of Public Safety, https://dps.mn.gov/divisions/hsem/em-resources/disaster-information (last visited June 23, 2025).
[13] "Billion Dollar Weather and Climate Disasters, Minnesota Summary, *NOAA National Centers for Environmental Information*, Billion-Dollar Weather and Climate Disasters | Minnesota Summary | National Centers for Environmental Information (NCEI)," https://www.ncei.noaa.gov/access/billions/state-summary/MN.

warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota's recreational economy.[14] These impacts will continue, and emissions from the Campbell Plant will contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois' farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.[15] In other years, extreme precipitation has threatened Illinois' agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose revenue.[16] Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois' 102 counties and the state logged 142 tornadoes—a new annual record.[17] These storms included a July 15, 2024 "derecho" that produced 100 mile-per-hour winds and 48 separate tornados.[18] In the

---

[14] *Id*.
[15] Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/ (last visited May 23, 2025).
[16] University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). See also U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).
[17] Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/ (last visited May 23, 2025).
[18] National Weather Service, July 15, 2024 Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20t

Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 "double derecho" and March 2023 storm.

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

The challenged Order declares an emergency based on a shortage of electric energy generation when there is no emergency. Even if there were an emergency, the Order imposes several requirements that are inconsistent with and exceed DOE's legal authority. And even if DOE had the authority to impose the requirements, they are not directed to actions that will actually meet the purported emergency.

The Order

The challenged Order is premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025. It notes that MISO "faces potential tight reserve margins during the summer 2025 period." Ex. 1 at 1 (emphasis added). It relies on the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Ex. 2. That report does not identify any war, fuel shortage, or natural disaster. *Id*. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. Ex. 2 at 5. Here are NERC's main conclusions regarding MISO:

---

he%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). See also David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by 'Ring of Fire', WBEZ CHICAGO, available at https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15 (last accessed May 23, 2025)

Midcontinent Independent System Operator (MISO): MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.

Id. at 5. NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id.* Indeed, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id.* at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions:

Risk Scenario Summary
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

Id. at 16.

The Order then describes how the Campbell Plant was scheduled to cease operations on May 31, 2025, and claims that the Campbell Plant's retirement would further decrease available dispatchable generation within MISO's service territory. Ex. 1 at 1. But NERC's analysis already

factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025.

The Campbell Plant's retirement was well known to MISO operators and accounted for in their robust resource planning processes described in further detail below. Indeed, the Order acknowledges that the retirement was already factored into MISO's own supply forecasts. *Id*. at 2. MISO's Planning Resource Auction Results for Planning Year 2025-26 ("PRA," Exhibit 3), cited in the Order, confirm adequate margin for a reliable summer season. *Id*.

Nonetheless, the Order determined than an emergency exists, and that "additional dispatch of the Campbell Plant is necessary," Ex. 1 at 2, even though the Campbell Plant was not included in any of the MISO forecasts finding sufficient capacity. It further based its determination "on the insufficiency of dispatchable capacity and anticipated demand" even though MISO had already determined that there was sufficient capacity to meet anticipated demand (Exs. 3-4) and NERC's Summer Reliability Assessment also does not conclude otherwise. Ex. 2 at *passim*. Nonetheless, the Order concludes with several imperatives:

- That Consumers Energy must take steps to ensure that the Campbell Plant is "available to operate." And that MISO "is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers" Ex. 1 ¶ A.
- That MISO is directed to provide DOE a report "concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest." Ex. 1 ¶ D.
- That "relevant government authorities" are directed to take such action and make accommodations as may be necessary to effectuate the dispatch and operation of the Campbell Plant if the MISO current tariff provisions "are inapposite." Ex. 1 ¶ E.

- That rate recovery is available pursuant to 16 U.S.C. § 824a(c) (also referred to as section 202(c) of the Federal Power Act). Ex. 1 ¶ G.
- That the Order runs through August 20, 2025. Ex. 1 ¶ H.

DOE's Order issued in error. The Department did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency. It starts from the proposition that there is only a "potential" for insufficient capacity that "could" result in a need for mitigation, which does not present an actual existing or imminent emergency. Plus, section 202(c)'s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. This Order, however, requires the Campbell Plant to be available to operate. Ex. 1 ¶ A. Nothing in section 202(c) grants DOE authority to order a plant to remain on standby in case an emergency occurs—especially absent any demonstrated need identified by the utility or grid operator. And even if an emergency did exist and DOE had the legal authority to issue an Order, directing a the Campbell Plant to participate in the bidding market using economic dispatch would not rationally the purported need (because there is no evidence the Campbell Plant can reasonably address any given future emergency need, because emergency responses do not require economic evaluation, and because the Campbell Plant takes so long to ramp up). It should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission[19] has authority to issue an order:

> [d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

16 U.S.C. § 824(c)(1). The same subsection states that the Commission may order "temporary connections of facilities" and "generation, delivery, interchange, or transmission of electric energy" that, in the Commission's "judgment will best meet the emergency and serve the public interest." *Id*. The next subsection, 16 U.S.C. § 824(c)(2), establishes that an emergency order must be limited to only those hours necessary to meet the emergency. It states:

> With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet

---

[19] The "Commission" refers to the Federal Power Commission (FPC), whose powers were transferred in 1977 to either the Secretary of DOE or the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 796(14); Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, 565-613 (1977). This transfer gave FERC the authority over "the interconnection, under section 202(b), of such Act [16 U.S.C. 824a(b)], of facilities for the generation, transmission, and sale of electric energy (*other than emergency interconnection*)." 42 U.S.C. § 7172(a)(1)(B) (emphasis added). However, this transfer also gave DOE "the function of the Federal Power Commission, or of the members, officers, or components thereof" except as provided in subchapter IV of the act. 42 U.S.C. § 7151(b). Because 42 U.S.C. § 7172(a)(1)(B) explicitly excludes emergency interconnection from FERC's authority, the authority over emergency interconnection has historically been delegated to DOE. However, the delegation of this emergency authority to DOE has not been consistently applied. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (1978), a petitioner objected to FERC's (not DOE's) failure to invoke emergency powers under 16 U.S.C. § 824a(c) and order utilities with excess capacity to supply the petitioner with energy. The court did not address whether FERC had the authority to declare an emergency to begin with. *Id*. Thus, whether FERC or DOE has the power to declare an emergency is inconclusive.

> the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Id. at § 824(c)(2).

The applicable regulations define "emergency," 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*.

10 C.F.R. § 205.371[20] (emphasis added).

III. Statement of Issues

Issue A: Did DOE have substantial evidence for its declaration of an emergency, and did it exercise reasoned decision-making in declaring that an actual emergency exists?

No. DOE relied on a NERC assessment that identified an elevated risk for potential capacity exceedance if an extreme weather event were to occur**.** Further, DOE failed to consider substantial countervailing evidence, including the MISO States' Integrated Resource Plans and MISO's PRA for the summer of 2025. The Order fails to identify any reasoned basis for concluding an actual emergency exists or is imminent.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual extant or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply

[20] DOE issued 10 C.F.R. §§ 205.370-379 pursuant to the Department of Energy Organization Act's transfer of emergency responsibilities to the Secretary of Energy.

situation. Did DOE exceed this authority where its Order is based on the nonspecific possibility that such a situation might occur over a period of several months?

Yes. An actual "emergency" is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The Order does not address any sudden occurrence needing imminent response, nor does it identify any actual and specific insufficient supply situation. Thus the Order is contrary to law.

Issue C. Section 202(c)(1) allows DOE to issue emergency orders requiring the "generation, delivery, interchange, or transmission of electric energy." Did DOE exceed this authority where its Order requires the Campbell Plant to take steps to be "available" to generate electricity and requires MISO to employ economic dispatch?

Yes. DOE's emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be merely available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because it is not confined to the types of actions allowed under section 202(c)(1), the Order is without authority and contrary to law.

Issue D. If DOE issues an order pursuant to 202(c)(1), then 202(c)(2) requires it to set limits on hours of operation and ensure that environmental impact is minimized. Did DOE exceed its authority by invoking section 202(c) to issue an Order that sets no specific hours of operation, places no limits on hours of operation, and adopts no specific requirements to minimize environmental impact?

Yes. The express statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Order does not establish any limited hours for operation, and at the same time it allows the Campbell Plant to potentially run at any and all hours for the entire 90 days covered bye the Order. It also does not meaningfully take steps to minimize adverse environmental impacts.

Because the Order does not set any specific hours the Campbell Plant must run, allows for unlimited hours for much of the summer, and doesn't meaningfully minimize adverse environmental impacts, the Order violates the requirements of section 202(c)(2). It is without authority and contrary to law.

Issue E: The Federal Power Act reserves resource adequacy planning to the individual states. Did DOE exceed its authority where its Order directly compels a plant slated for retirement to take steps to be available to operate?

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). Because DOE's Order exceeds its authority by contradicting Michigan's resource plans, it is contrary to law.

Issue F: The states retain primary authority for developing and establishing Integrated Resource Plans or Strategic Energy Plans that get factored into MISO's tariffs. The Order directs "relevant governmental authorities" to accommodate the Order. Does this portion of the Order violate the Tenth Amendment, exceed DOE's authority, and impose arbitrary-and-capricious requirements not based on substantial evidence?

Yes, on all fronts. This section of the Order is incomprehensible and unexplained. It violates the Tenth Amendment to the extent it directs state or local officials to carry out the Order. And Section 202(c) does not include authority to order any unit of government to take any particular action. For all of these reasons, the Order is contrary to law.

Issue G: Even if DOE were correct that an emergency exists and that it had the authority to issue the Order, will the Order's requirements rationally meet the emergency?

No. Section 202(c) contemplates emergency orders that are precisely tailored to meet the specific emergency.16 U.S.C. § 824a(c). Emergency generation is not economic dispatch. Plus, the Campbell Plant is high cost and uneconomical, it requires a long time to ramp up, and there is

no reason to think it would be used to meet any shortfall if one were to happen given other considerations such as transmission infrastructure. The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is not rationally related to the emergency it purports to address, so the Order is without substantial evidence and lacks reasoned decision-making.

IV. Description of MISO

MISO is a regional transmission organization (RTO), an independent, non-profit, membership-based organization responsible for optimizing generation and transmission of electricity and ensuring the reliability of the electric power system within its region, consisting of nearly 3,000 generating units.[21] 18 C.F.R. § 35.34(a), (j)(1). MISO administers bulk or wholesale power markets that centrally commit and dispatch power to facilitate least-cost and reliable power production and delivery throughout the region. The wholesale markets within MISO signal and value power needs and identify the most economically efficient way—the least-cost approach where demand for energy equals the cost supplied—to meet them across the system.[22] MISO also works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.[23] MISO uses advanced

---

[21] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.
[22] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.
[23] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).

modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.[24]

MISO planned for adequate capacity during the summer of 2025: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex. 3 at 2. It reports: "it is important to recognize existing processes have *cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order*." *Id*. (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*.

The long-planned retirement of the Campbell Plant is not an impediment to summer reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating units.[25] That trend is shown below in the bar graph (from MISO's 2023 Transmission Expansion Plan Report[26]), which displays the retired capacity by generation type over time:

---

[24] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

[25] *See also* MISO, *Approved Generator Retirements (Public) as of June 28, 2024* ("*Approved Retirements 2024*"), https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).

[26] MISO, *2023 Transmission Expansion Plan*, available at https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf.

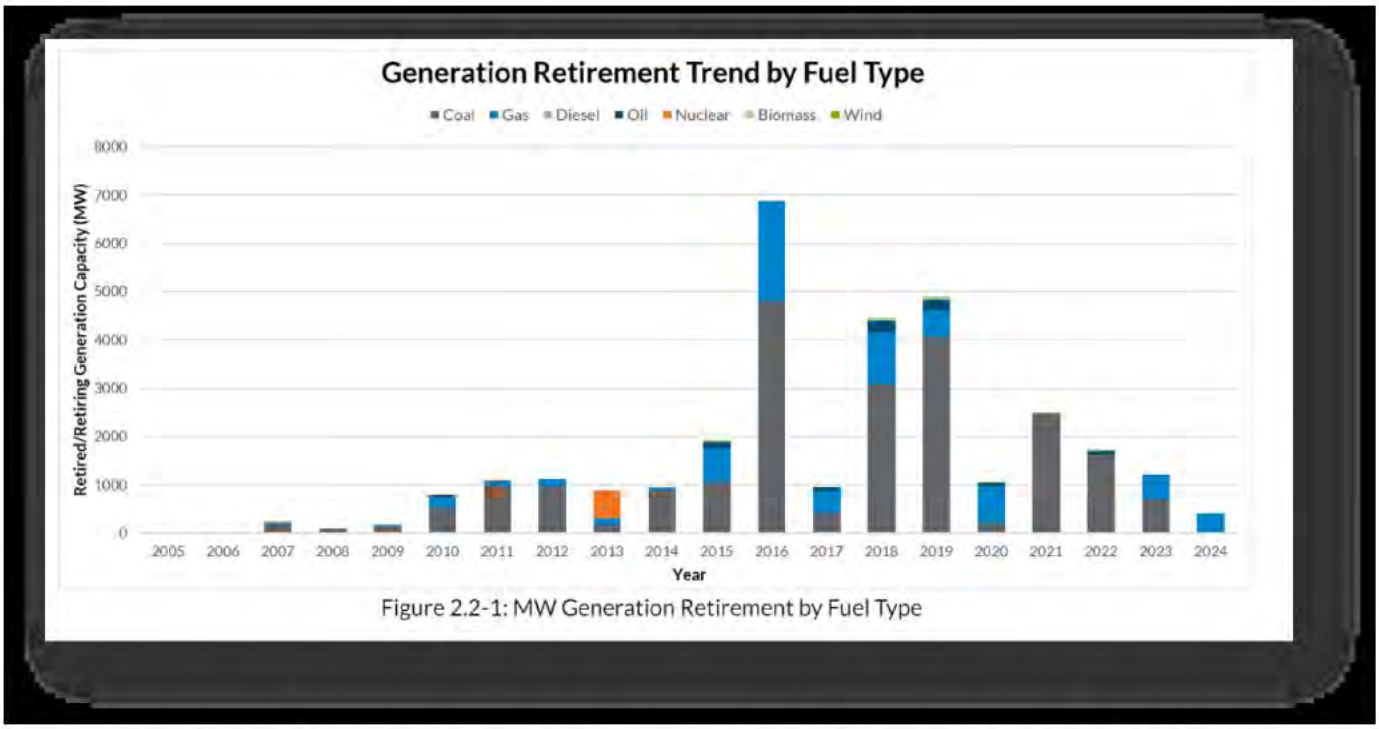


Figure 2.2-1: MW Generation Retirement by Fuel Type

Through use of generation capacity and transmission infrastructure planning, the addition of new capacity—in particular renewables, and the implementation of the other measures discussed above, MISO has been able to absorb these retirements and maintain overall system reliability. *Id*. at 34-35.

V. Argument

A. The Order lacks substantial evidence demonstrating the existence of an actual emergency and DOE failed to engage in reasoned decision-making.

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE's determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 825l. After an objection has been brought before DOE, the Court may consider it with the understanding that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 16 U.S.C. § 825l. Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Duke*

Energy Corp. v. FERC, 892 F.3d 416, 420 (2018). This standard implies deference to an agency's factual determinations. *See, e.g., id*.

While DOE failed to provide substantial evidence of a current and unexpected emergency, the evidence DOE provided, does prove however, that there is currently no energy emergency and will not be an "unexpected emergency" that warrants this Order. MISO is well situated to deliver reliable power throughout its area in the summer of 2025.

In declaring the contrary, DOE relied on a NERC assessment that identified an elevated risk for potential capacity exceedance if an extreme weather event were to occur**.** But the Order makes too much out of too little—the "elevated" category is hardly a call for immediate and unnecessary emergency action. As the NERC assessment points out, MISO expects to have an existing certain capacity of 142,783 MW during the summer—a figure that factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025 and that exceeds both expected demand and the reserve margin[27] anyway. While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. To the contrary, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The "elevated risk" category is not tantamount to an emergency. Even though NERC used the term "elevated risk" for the possibility that there could be an operating reserve shortfall, NERC did not apply the "high risk" category to MISO, and did not call for any retired plants to be brought

---

[27] MISO PRA, Results for Planning Year 2025-26 at 18 (Corrected May 29, 2025).

back online. Ex. 2. at 5. Moreover, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions: *Id*. at 16. The "elevated risk" designation is also far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated as at "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[28] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021. *Id*. Yet no energy shortage has occurred and DOE has never imposed an emergency declaration until now.

Such a declaration is simply unnecessary when considering the bigger picture. DOE clearly erred in its consideration of the evidence, *see Wisconsin Power & Light Co. v. FERC*, 363 F.3d 453, 461 (D.C. Cir. 2004) (an appeals court "must consider . . . 'whether there has been a clear error of judgment.'"), including the contradiction in the Order's citation of MISO's PRA for the summer of 2025 which contrary to the Order actually found sufficient capacity throughout the region. The PRA provides a strong conclusion that supply will be adequate. Ex. 3. The press release announcing the PRA, (Exhibit 4), confirms "adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026)." Ex. 4. And while "the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint." *Id*. The PRA was based on NERC's standard

---

[28] *See* NERC, *Reliability Assessments,* https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited June 23, 2025).

BAL-502-RF-03 (Exhibit 5), requiring assessment of "one day in ten year" loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO will have sufficient capacity through the summer of 2025. Exs. 3-4. MISO's PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

Indeed, in MISO's Answer to the cost-recovery docket dated June 19, 2025, MISO highlights the PRA when it describes its certainty it has planned for adequate capacity: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex.10 at 2. It further writes, "it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order." *Id*. (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*. This recent submission undermines DOE's conclusions in the order that MISO faces insufficient capacity.

DOE failed to consider recent comments by MISO's Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC's purported concerns. See Exhibit 11. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has

since been revised[29]) that included capacity shortfalls in 2025, noting that NERC's assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be "more than adequate," and that he had "no material concerns" over MISO's resource adequacy for the upcoming summer.

DOE also failed to consider MISO's history of strong performance through several extreme weather events including Winter Storms Elliot and Uri, and did not credit MISO's proven track record of engaging in a variety of mechanisms to ensure grid reliability.

DOE further failed to acknowledge that no part of MISO is currently afflicted by any unexpected outage or extreme weather event, and the entire system is running as planned with no outages, unexpected demand, lack of fuel or water, or other such emergencies in place at the time of the order.

Given all of these countervailing considerations, DOE did not have substantial evidence supporting its emergency determination. It did not exercise reasoned decision-making in declaring that an emergency exists. Its Order is arbitrary and capricious.

B. The Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371.

An actual "emergency" is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. The statute describes the temporary response needed to address a sudden event by its black-letter terms. 16 U.S.C. § 824a(c). And Department regulations define "emergency" to mean an unexpected inadequate supply of

---

[29] NERC, *Statement of NERC's Long-term Reliability Assessment*, (June 17, 2025) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx?utm_source=substack&utm_medium=email.

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." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1 & 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[30]

[30] MISO, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023) ("*Winter Storm Elliott Overview*") at 7, https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

While DOE's emergency powers have occasionally been used to address retirements like the Campbell Plant, it has done so only when requested by the operator or local government and there was a specific need demonstrated for the units to operate due to an unexpected emergency. DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant to supply Washington D.C. when transmission lines were out of service); DOE Order No. 202-17-1 at 2 (Grand River Energy to operate Unit 1 due to lighting strike to Unit 2 and delay in construction for Unit 3); DOE Order No. 202-17-2 (need to operate Yorktown to avoid imminent risk of load-shedding).

A memorandum by the Congressional Research Service, Exhibit 12, confirms that DOE's use of Section 202(c) to order a plant to be generally available is novel. Ex.12 at 3 (Department engaging in "seemingly new interpretations of the emergency authority").

Courts have also likewise recognized Section 202(c)'s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply." 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm'n*., the Eighth Circuit noted that 202(c) provides authority to "react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency." 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that a separate provision, section 202(b) [31] applies to the former, while section 202(c) applies to the latter:

---

[31] Section 202(b) refers to 16 U.S.C. § 824a(b), which states "[w]henever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

Otter Tail Power Co., 429 F.2d at 234. In that case, a power company challenged the FPC's order issued under § 202(b) of a temporary connection between the power company and a small municipally owned power producer that was "dangerously close to eroding its firm power supply" due to the proximity between the generator load capacities and the peak load demand. *Id.* It claimed that because the ordered connection was temporary, the order could only be issued under section 202(c), and only in emergency conditions. *Id.* The court disagreed that section 202(c) only applies to temporary orders but agreed that a potential crisis in the foreseeable future was not an emergency, making it "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)." *Id.* The caselaw is therefore clear: for DOE to have any authority under section 202(c) the emergency must be actual and not merely a broadly asserted projected risk.

DOE exceeds its authority because the Order does not address any actual emergency or sudden occurrence needing imminent response, and because it has not identified any actual and specific insufficient supply situation. Thus the Order is without authority and contrary to law.

---

by order direct a public utility" if the utility would not face an undue burden. The DOE's authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

C. The Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1).

DOE's power is limited to orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant availability untethered to meeting any specific need, nor does it allow for potential economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur, and specifically does not allow for the Department to order availability without a specific need to be available.[32] Plus, "Economic dispatch" is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean only the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO's determination of lowest-cost sources may not result in the Campbell Plant producing *any* generation whatsoever. Thus the Order is without authority and contrary to law.

D. The Order exceeds DOE's authority because it does not set any hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3).

The order must be limited to only those hours necessary to meet the emergency. 16 U.S.C. § 824a(c)(2).

The Order addresses only the potential for an emergency, but does not identify a need for the Campbell Plant to generate electricity to meet it. By the same token, the Order does not establish any limited hours or other parameters for the Campbell Plant to follow to ensure it meets

[32] Of the 19 times the DOE has issued a 202(c)(1) Order, only once, for Mirant in 2005, did it require a plant to supply as-needed additional capacity—but even then it was based on a specific application demonstrating a concrete and specific need. DOE Order No. 202-05-3 (Dec. 20, 2005). That is not the case here.

the purported emergency, only that it be available at all times. Thus the Order is without authority and contrary to law, and allows the Campbell Plant to generate electricity during times there are not even "elevated risks." Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the environmental impacts that, by law, the Order must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus the Order is without authority and contrary to law.

E. The Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states.

Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). Decisions over what plants should be constructed or retired is traditionally subject to state regulation. States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). "The states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy" *Coal. for Competitive Elec., Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2d Cir. 2018). What facilities to build, whether they remain feasible, and utility rates are areas governed by the states. *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

The energy market is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the Federal Power Act—which explicitly declares that the Federal Energy Regulatory Commission may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission.") 16 U.S. Code § 824h(b). Indeed, FERC has embraced these cooperative federalism principles and developed long-

standing consultation practices with the states, including through creation of a Joint Federal-State Task Force. Exhibit 8. And more recently, a Federal-State Current Issues Collaborative. Exhibit 9.

Section 103 of the Department of Energy Organization Act is also applicable; it mandates due consideration to state retirement plans and requires, where practicable, consultation with relevant state officials. 42 U.S.C. § 7113.

States are responsible for developing and approving power generation plans, typically through public commissions like the Public Utilities Commission[33] in Minnesota, the Public Service Commission.[34]. These bodies oversee the development of Integrated Resource Plans ("IRPs"), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota's IRP statute). An IRP can consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.[35] Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.[36]

---

[33] Minnesota Public Utilities Commission, *Utility Planning*, https://mn.gov/puc/activities/economic-analysis/planning/ (last visited June 23, 2025).
[34] Wis. Stat. Ann. § 196.491 (West).
[35] *Id*.
[36] Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last visited June 23, 2025).

MISO, in turn, is one of the country's largest regional transmission organizations (RTOs), which were formed to develop transmission systems, trading markets, and attendant procedures.[37] MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.[38] This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[39] MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And MISO then accounts for the final IRPS in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.[40] MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual Planning Resource Auction ("PRA"), which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.[41]

The Campbell Plant's planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including

---

[37] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf
[38] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).
[39] *Id*.
[40] *Id*.
[41] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022). The MPSC approved of Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id*. at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether the retirement will pose any concern for grid reliability. [42]

Consumers Energy submitted the Attachment Y form to MISO on December 14, 2021, providing notice that it planned to suspend generation at the Campbell Plant by June 1, 2025. MISO approved the Campbell Plant's retirement on March 11, 2022. In making its approval, MISO determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria."

DOE did not adequately consult with the state, much less account for or incorporate the findings of MISO in approving Consumer's Energy's Attachment Y submission. Michigan state regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in

[42] If MISO does identify a threat to grid reliability if the resource retires, the MISO tariff provides a mechanism to retain that resource until the constraint can be alleviated.

their states including the Campbell Plant. *Zibelman*, 906 F.3d at 50. DOE's failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of Federal Power Act regarding federal-state collaboration and upends FERC's historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely "practicable" here given the lack of an imminent emergency and the Order did not give any consideration (much less due consideration) to Michigan's IRP. 42 U.S.C. § 7113.

The Order usurps the State of Michigan's primary rule in resource planning and development; it is contrary to law.

F. The Order impermissibly calls for state governments to assist in its execution.

As discussed in the previous subsection, states retain jurisdiction over facilities used for the generation of electric energy and play a key role in development of MISO's tariff provisions. The Order mandates that to "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, *the relevant governmental authorities* are directed to take such action and make accommodations as may be necessary to do so." Order ¶ E. As applied to state and local authorities, this mandate is unlawful for several reasons.

First, the Order violates the Tenth Amendment by commandeering state and local officials to implement a federal program. *See, e.g.*, *Printz v. United States*, 521 U.S. 898, 933 (1997). While the Order is not specific as to the object or the nature of its direction to "government authorities," vagueness does not erase the constitutional infirmity; it exacerbates it. *Cf. Murphy v. NCAA*, 584

U.S. 453, 469 (2018). All the more so where the Order lacks specific limited hours for operation and environmental conditions as discussed in Section D above.

Second, the Order violates the plain terms of Section 202(c), which does not grant authority to issue any order directing any governmental authority to do anything. 16 U.S.C. § 824a(c)(1). Third, the Order does not explain why directing state officials to act (or refrain from acting) pursuant to the powers reserved to them by the Constitution would help achieve the Order's purposes, and DOE lacked substantial evidence to support such a conclusion.

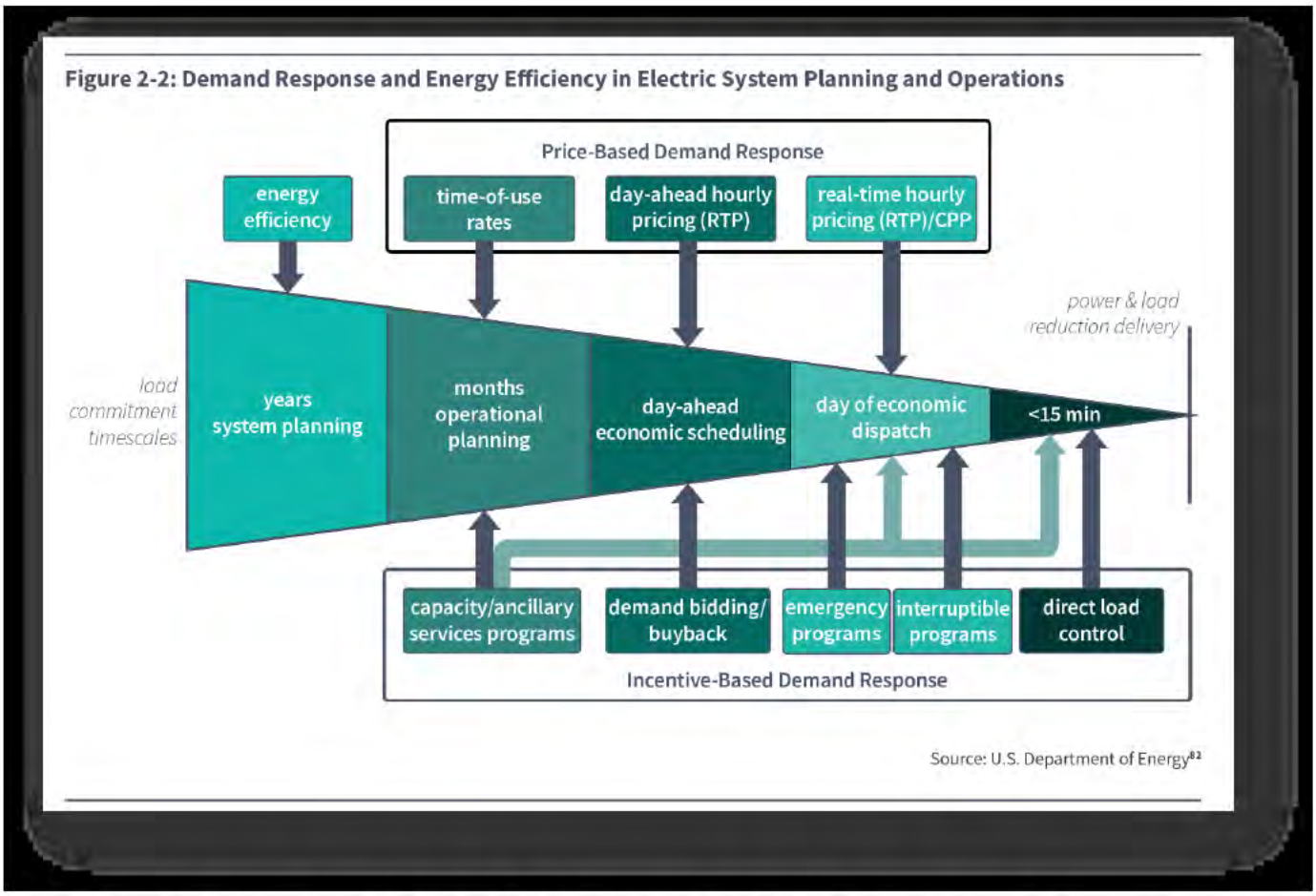
G. The Order is unreasoned, arbitrary, and capricious because the actions it mandates will not meet the purported emergency.

Section 202(c) contemplates emergency orders that are tailored to the specific emergency—they must "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). Even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to address the emergency that the order identifies.

The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is noteworthy. Economic dispatch is a term of art for the procedure by which MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. Beyond must-run units, MISO dispatches additional capacity from generators in increasing order of their respective costs, starting with the cheapest sources and moving up to more expensive ones as demand increases. MISO will also consider longer-term forecasts of generation given constraints such as forced outages and to ensure adequate margin. And then MISO monitors the grid in real time and calls upon available capacity as needed the day-ahead or day-of markets.

"Economic dispatch," by definition, is awarded to the lowest-cost option (all else being equal). Exhibit 6. That is because much of the base load planning takes place years or months

ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:



FERC *Energy Primer*, *supra* n.37 at 43. As explained by DOE's 2007 Report to Congress on economic dispatch, most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Exhibit 6 at 6. A 2024 report from the Government Accountability Office, Exhibit 13, found that based on 2021 data the vast majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal.

Taken together, economic dispatch considers a variety of factors including (1) the cost of generation, (2) the standby condition of the generator, (3) ramp-up time to provide the needed capacity, and (4) whether electric energy can be transmitted to the area of need.

In the context of an emergency, however, plants are generally allowed to run without regard to lowest-cost considerations or bid-submission-and-selection processes. The Order's proposed solution for "economic dispatch" of the Campbell Plant is wholly incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, an even uneconomic plants receive cost-of-service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a "price taker" using MISO's "must run" classification. Thus, the order does not use "economic dispatch" in a rational way because an emergency is not addressed with economic dispatch.

Moreover, coal is an expensive fuel type in our current energy mix—indeed the inefficiency of running a coal plant makes it economic in general, and is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

The Order also does not cite to any evidence that economically dispatching the Campbell Plant will be the appropriate solution for amorphous purported emergency—which is only that a need *might* arise in the future. If, for example, there were a need for additional electricity in North Dakota, it is not likely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Campbell Plant to meet that need. And if the need occurs in the day-of or real-time markets, the Campbell Plant will not be able to spool up in time to meet

that need, either. That is because it takes over 12 hours to reach peak load. Exhibit 14.[43] And even if there were adequate transmission and lead time, the Campbell Plant still uses an expensive fuel source. If the Campbell Plant's bid is higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), then it would not be selected as the most economic resource to meet the need.

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Order improperly imposes measures that are not tailored to anything. All the while, the Order imposes costs on the States to maintain an idle plant, adds potentially expensive generation to the mix if it ever were to run, and would generate harmful pollution at the same time. Thus, the Order requiring the Campbell Plant to remain available and for MISO to take steps to use the Campbell Plant for economic dispatch is irrational and arbitrary where the Campbell Plant is unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need it is supposed to meet in the first place.

Therefore, the Order is not rationally related to meeting the need of the purported emergency that it identifies.

CONCLUSION

For all of the foregoing reasons, the Department should rescind the Order.

---

[43] Adapted from U.S. Energy Information Administration submissions according to Forms EIA-860 and EIA923, in which "OVER" indicates ramp-up time exceeding 12 hours. *See* https://www.eia.gov/electricity/data/eia860/; https://www.eia.gov/electricity/data/eia923/.

KEITH ELLISON
ATTORNEY GENERAL
OF MINNESOTA

/s/ Peter Surdo
Peter Surdo
Cat Rios-Keating
Alyssa Bixby-Lawson
Special Assistant Attorneys General
Office of the Minnesota Attorney General
445 Minnesota St., Suite 600
St. Paul, MN 55101

Dated: June 23, 2025

KWAME RAOUL
ATTORNEY GENERAL OF
THE STATE OF ILLINOIS

/s/ *Samuel C. Lukens*
Samuel C. Lukens, Assistant Attorney General
Susan L. Satter, Chief, Public Utilities Bureau
Jason E. James, Assistant Attorney General
Office of the Illinois Attorney General
115 South LaSalle, 25th Floor
Chicago, Illinois 60603

Dated: June 23, 2025

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy 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 portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id*.
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025



Table of Contents

About this Assessment 4
Key Findings 5
Resource Adequacy Assessment and Energy Risk Analysis 5
Other Reliability Issues 7
Recommendations 8
Summer Temperature and Drought Forecasts 9
Risk Assessment Discussion 10
Assessment of Planning Reserve Margins and Operational Risk Analysis 10
MISO 16
MRO-Manitoba Hydro 17
MRO-SaskPower 18
MRO-SPP 19
NPCC-Maritimes 20
NPCC-New England 21
NPCC-New York 22
NPCC-Ontario 23
NPCC-Québec 24
PJM 25
SERC-Central 26
SERC-East 27
SERC-Florida Peninsula 28
SERC-Southeast 29
Texas RE-ERCOT 30
WECC-Alberta 31
WECC-Basin 32
WECC-British Columbia 33
WECC-California 34
WECC-Mexico 35
WECC-Rocky Mountain 36
WECC-Northwest 37
WECC-Southwest 38
Data Concepts and Assumptions 39
Resource Adequacy 41
Changes from Year to Year 42
Net Internal Demand 43
Demand and Resource Tables 44
Variable Energy Resource Contributions 50
Review of 2024 Capacity and Energy Performance 51
Eastern Interconnection–Canada and Québec Interconnection 51
Eastern Interconnection–United States 51
Texas Interconnection–ERCOT 52
Western Interconnection 52
Western Interconnection–Canada 52
Western Interconnection–United States 52

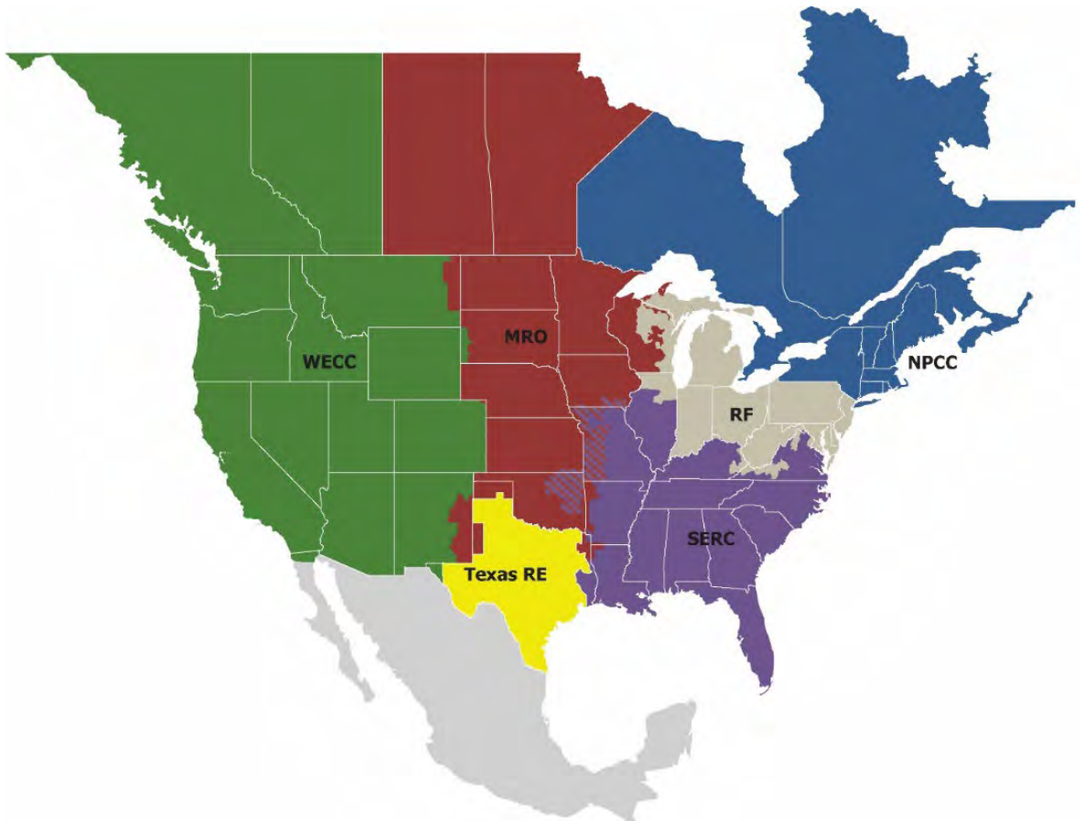
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

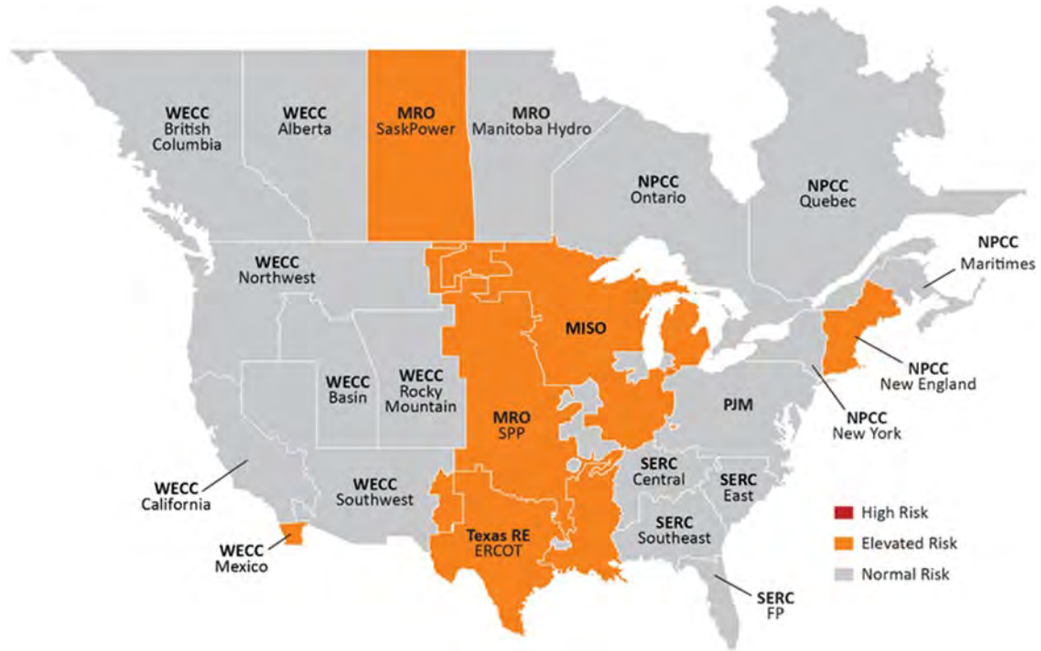


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

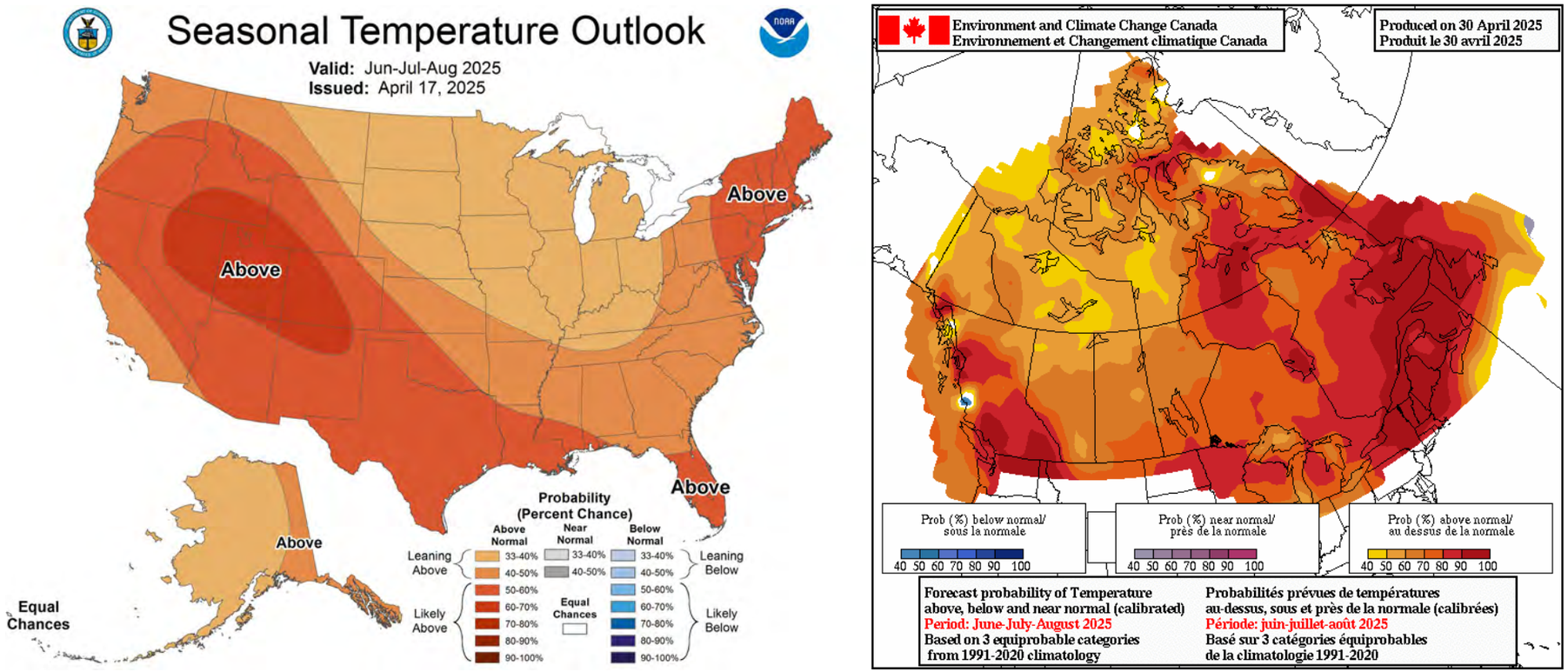


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

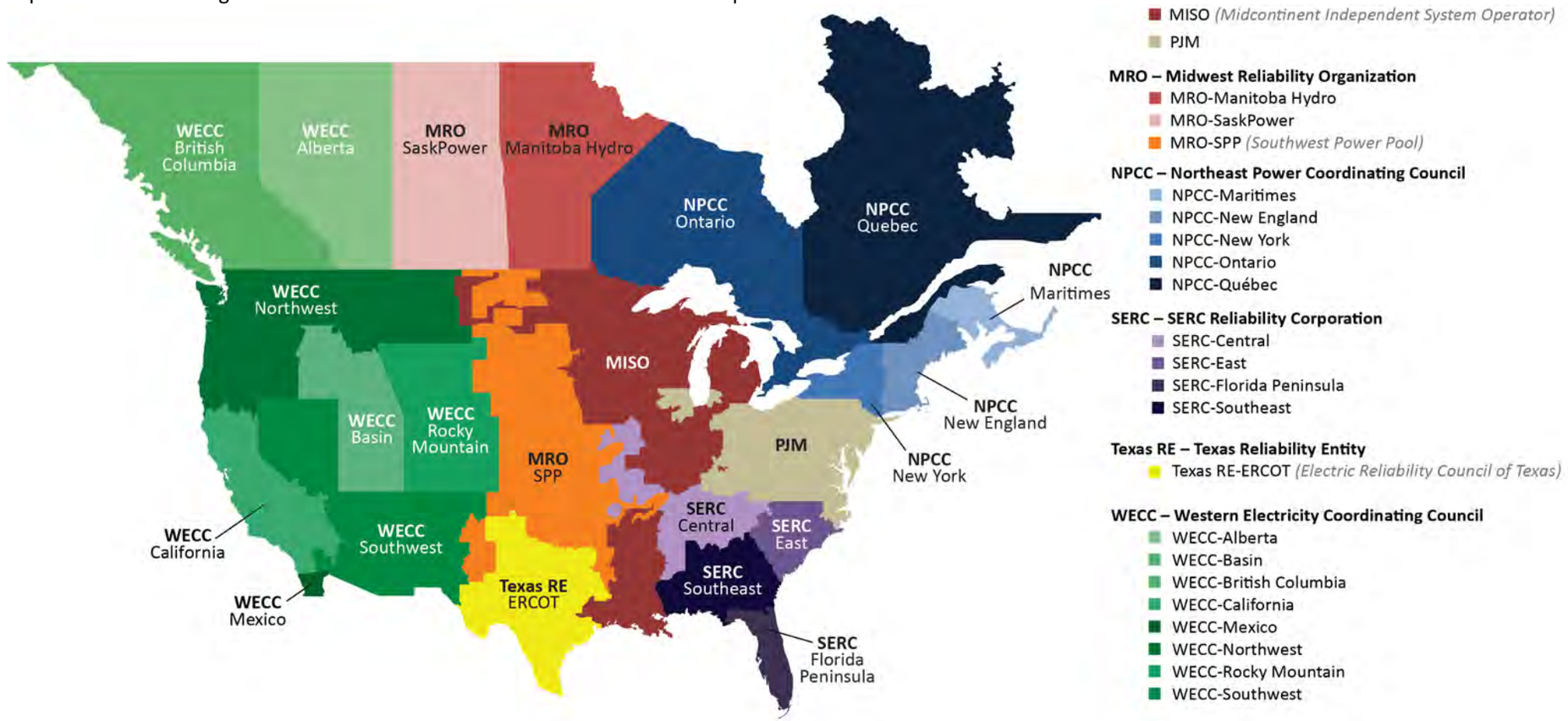
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





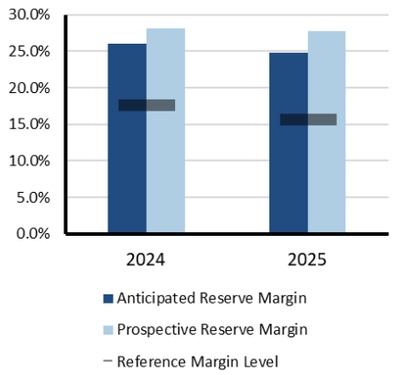
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

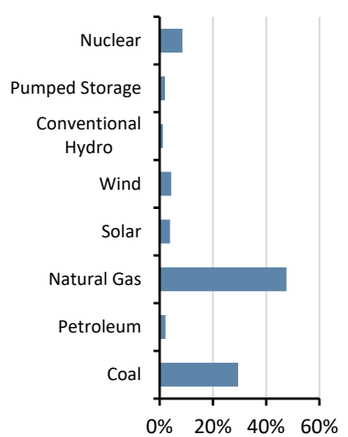
On-Peak Reserve Margin



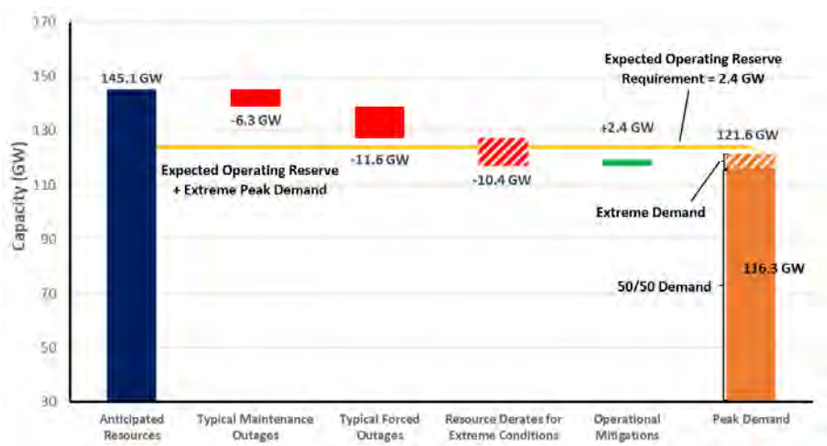
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

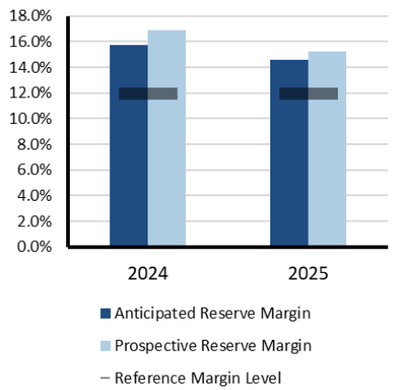
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

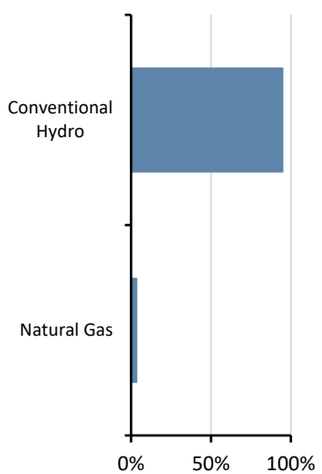
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

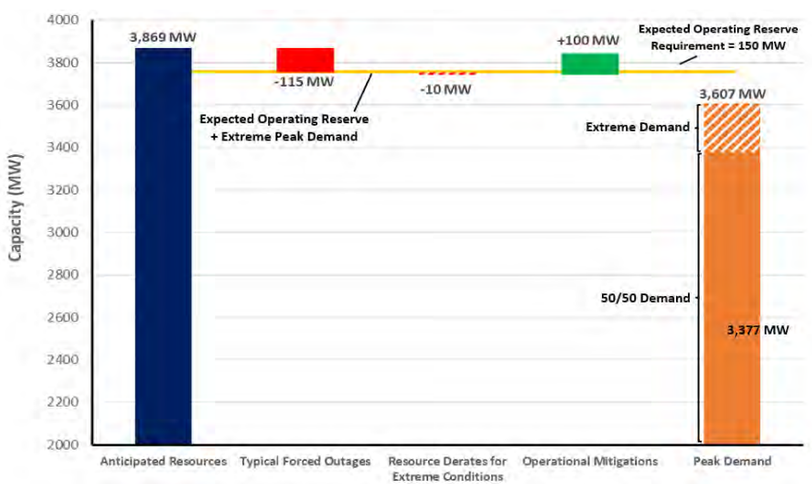
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

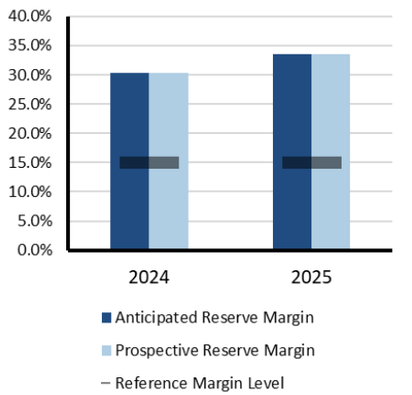
Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

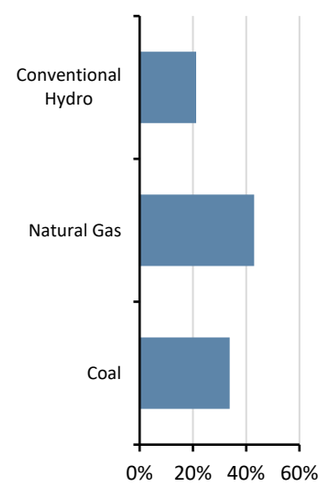
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

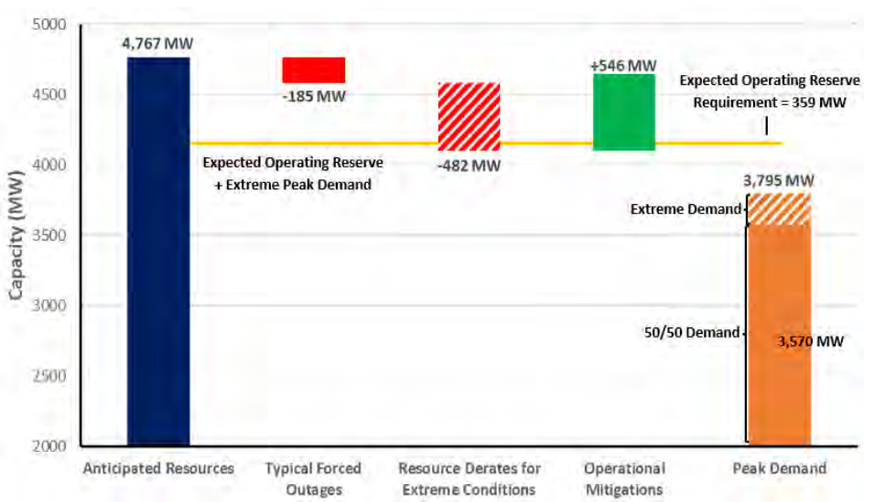
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice



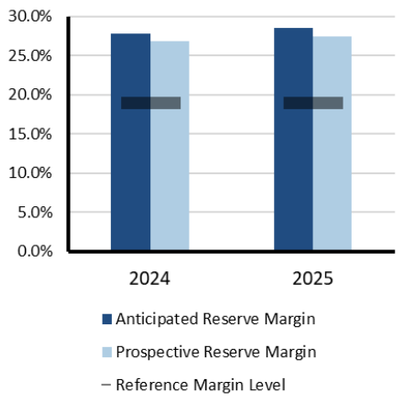
MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

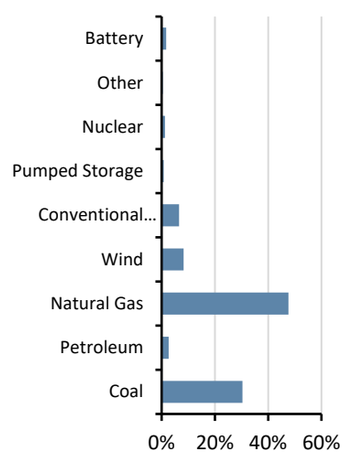
On-Peak Reserve Margin



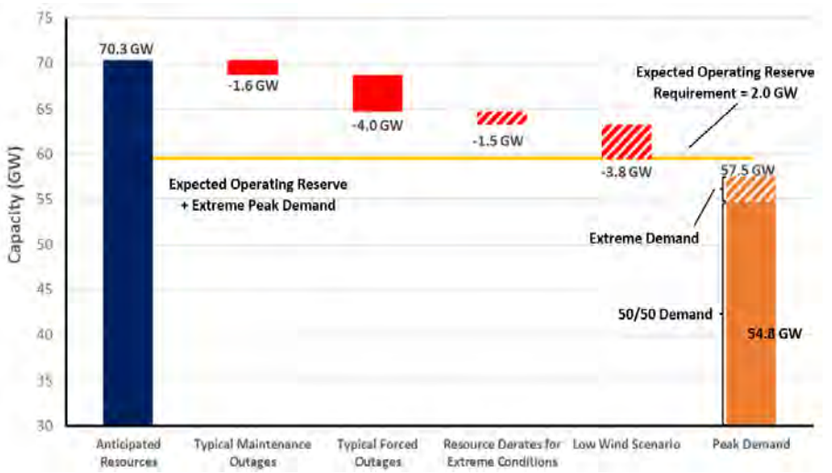
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer



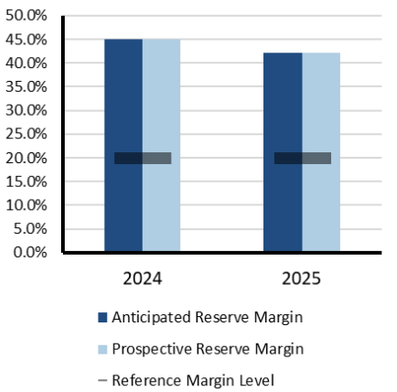
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

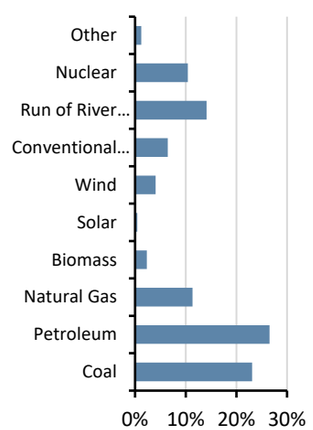
On-Peak Reserve Margin



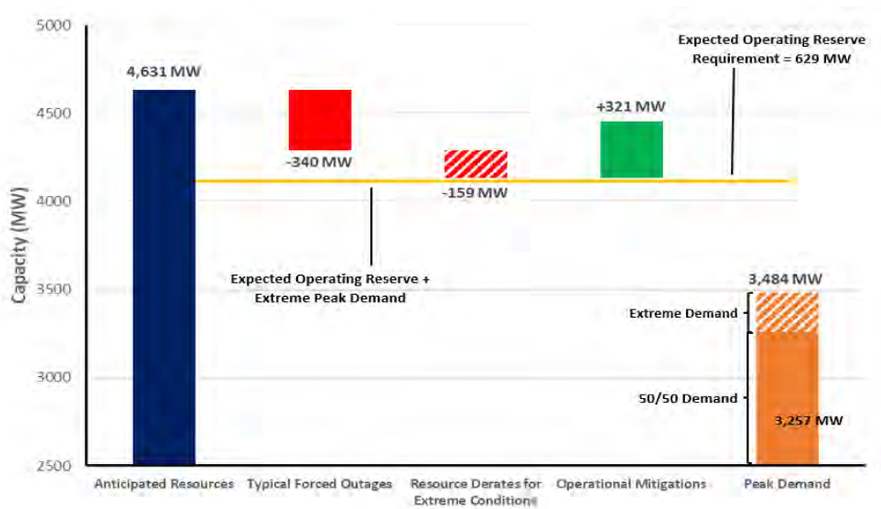
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)



NPCC-New England

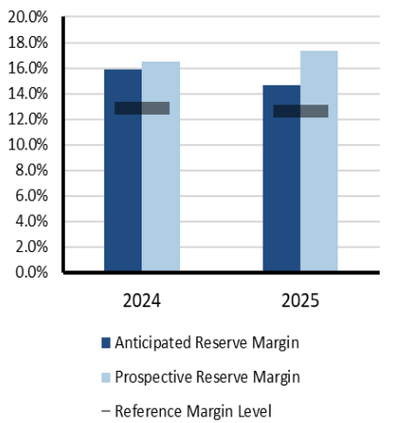
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

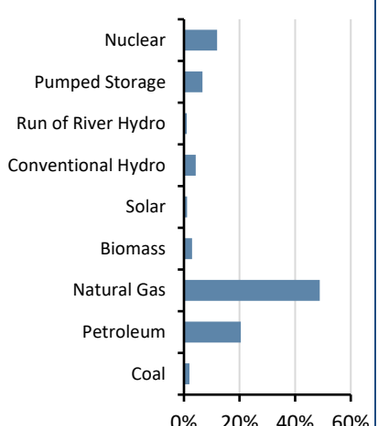
On-Peak Reserve Margin



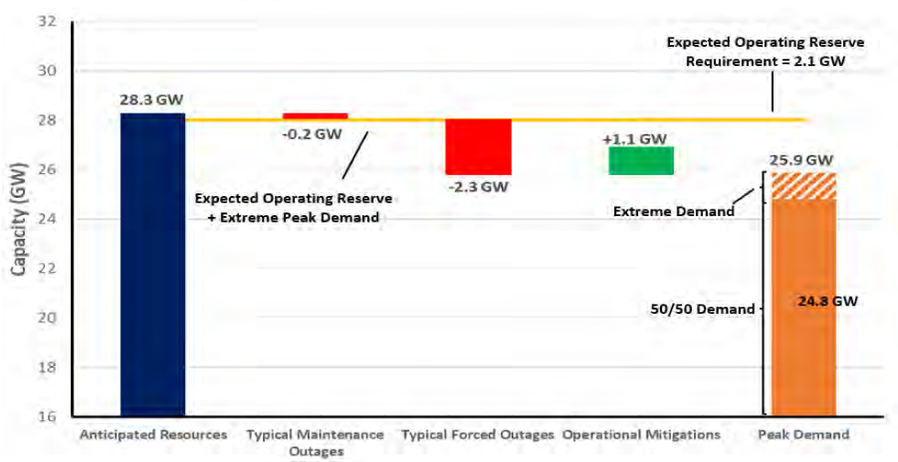
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

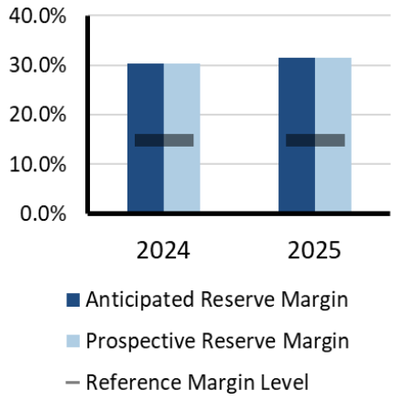
Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

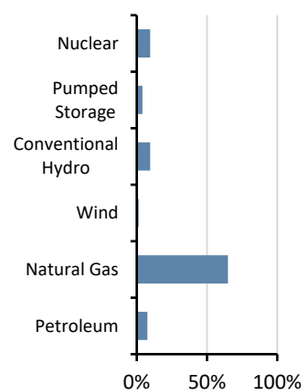
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

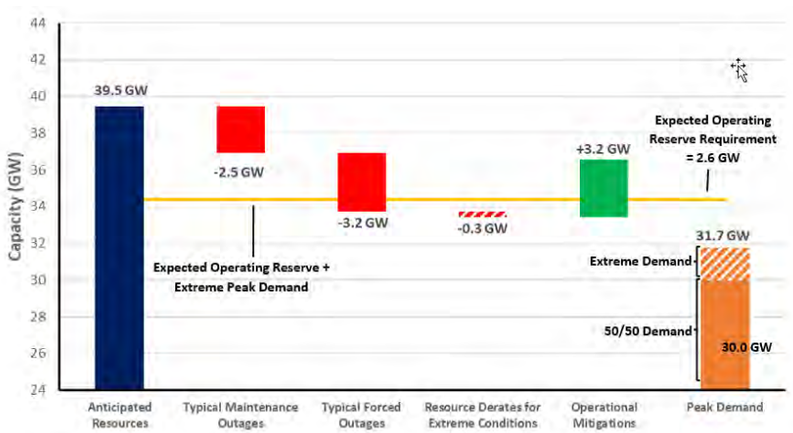
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

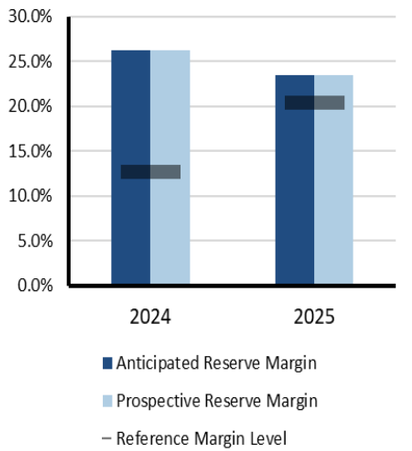
Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

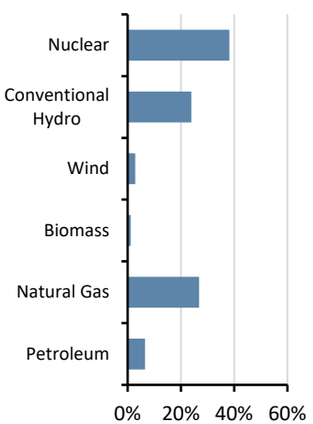
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

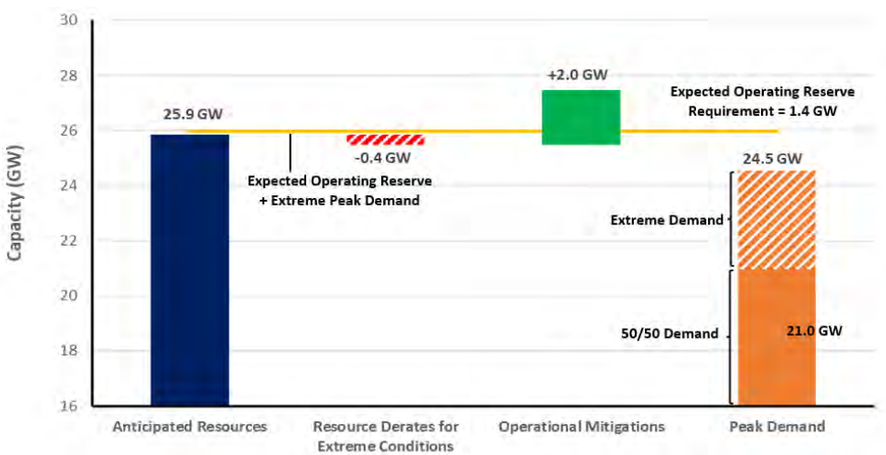
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.



NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

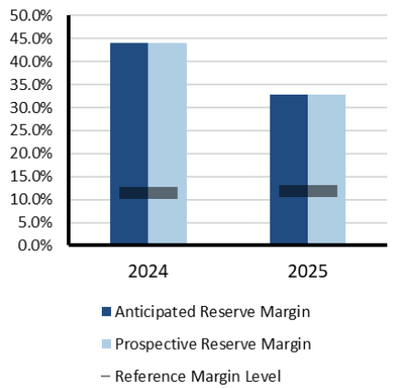
Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

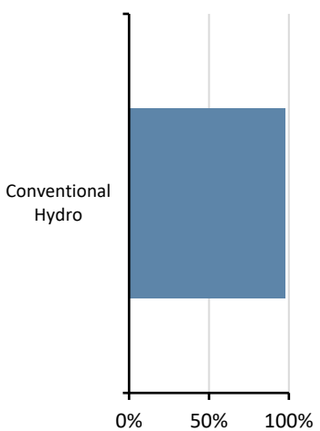
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

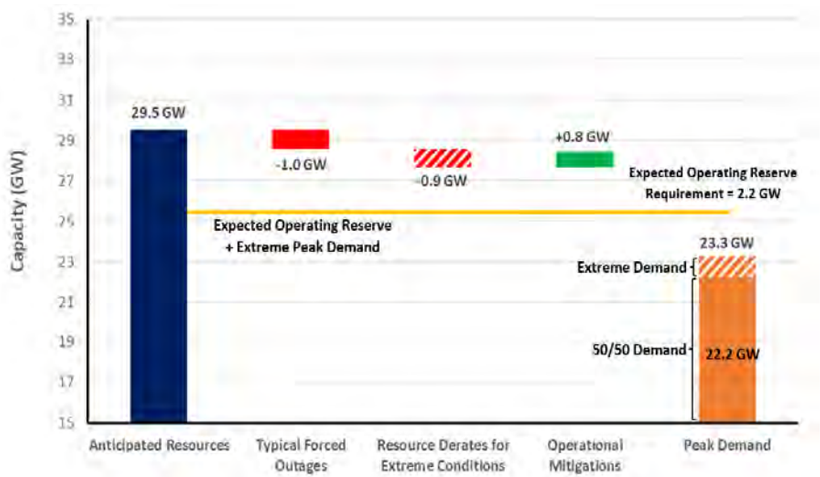
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

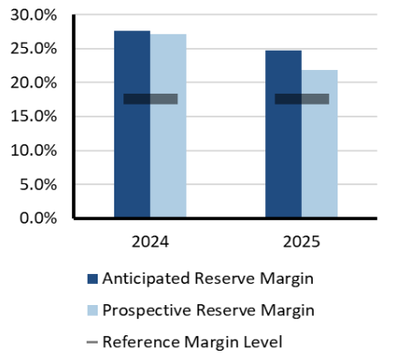
Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

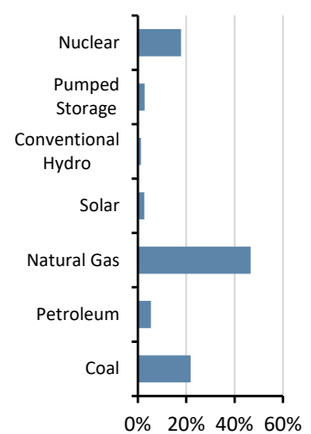
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

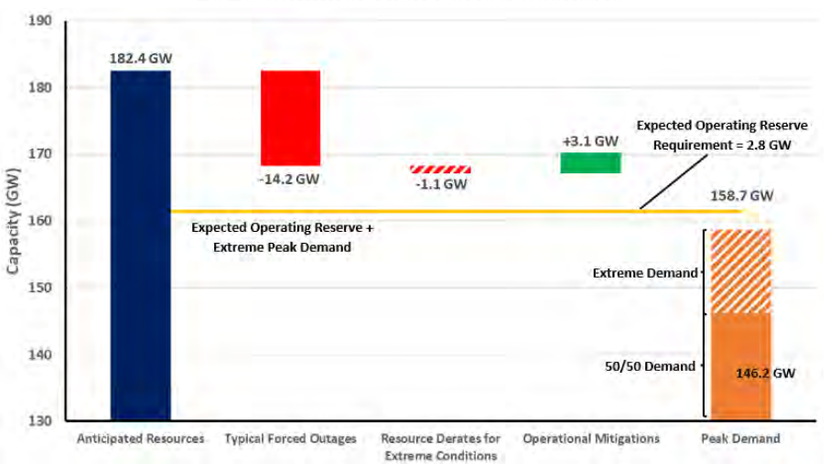
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



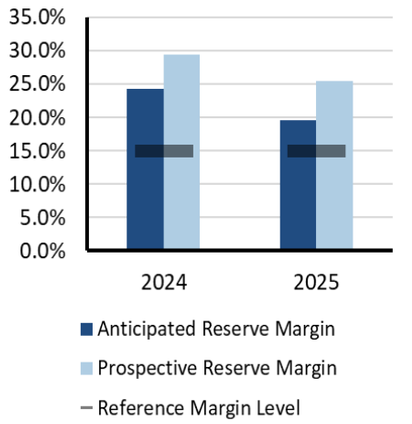
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

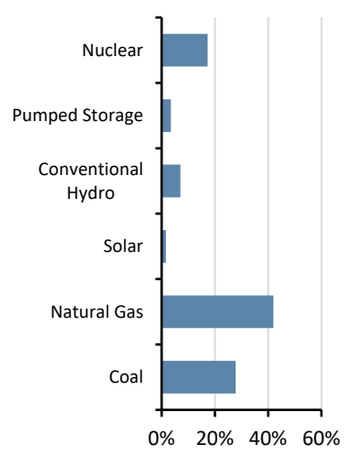
On-Peak Reserve Margin



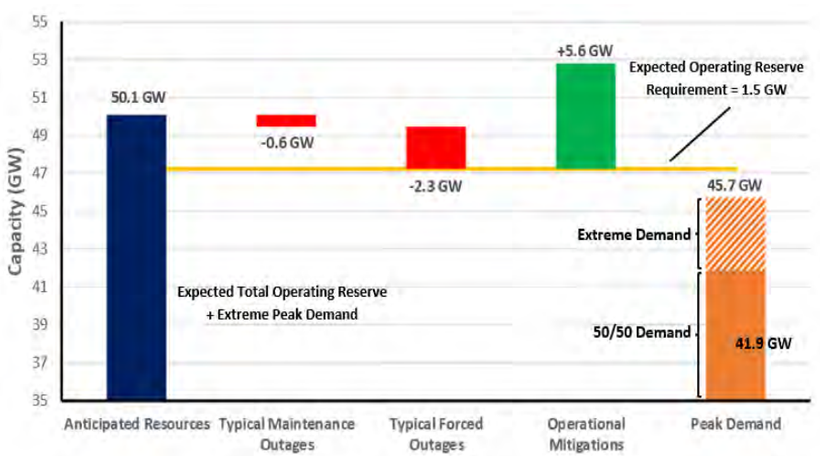
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures



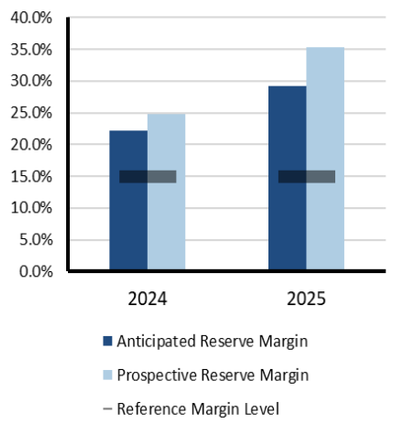
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

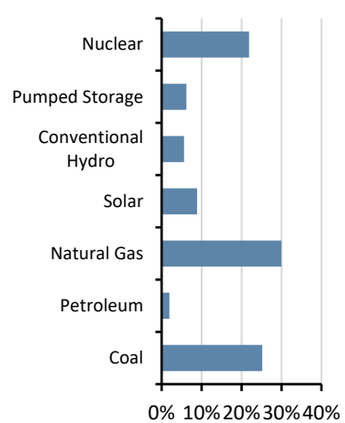
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures



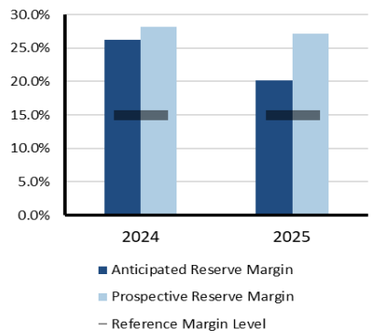
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

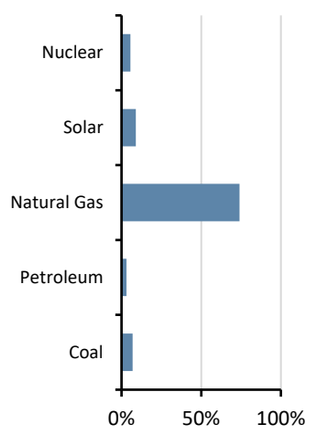
On-Peak Reserve Margin



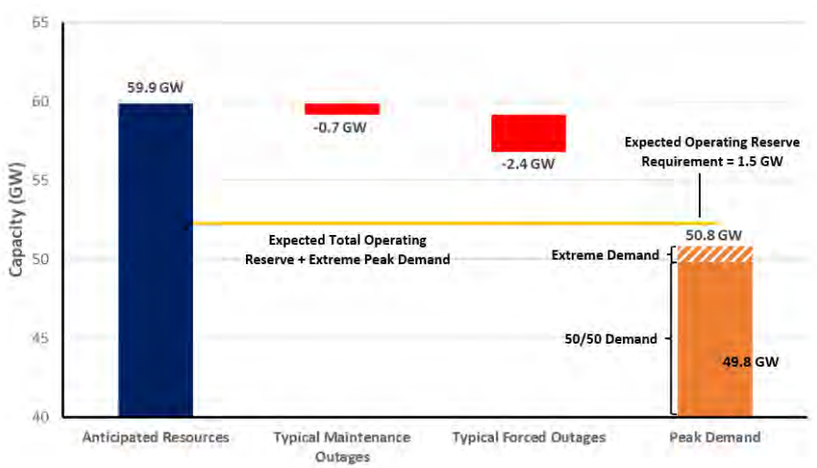
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



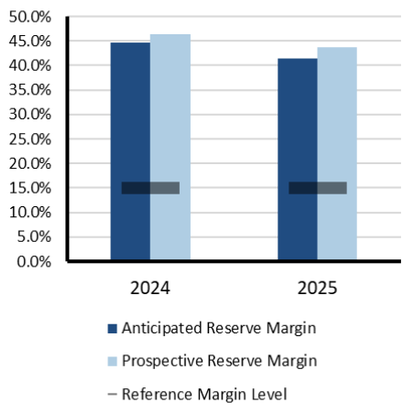
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

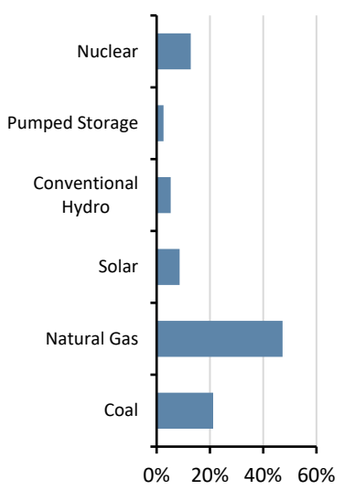
On-Peak Reserve Margin



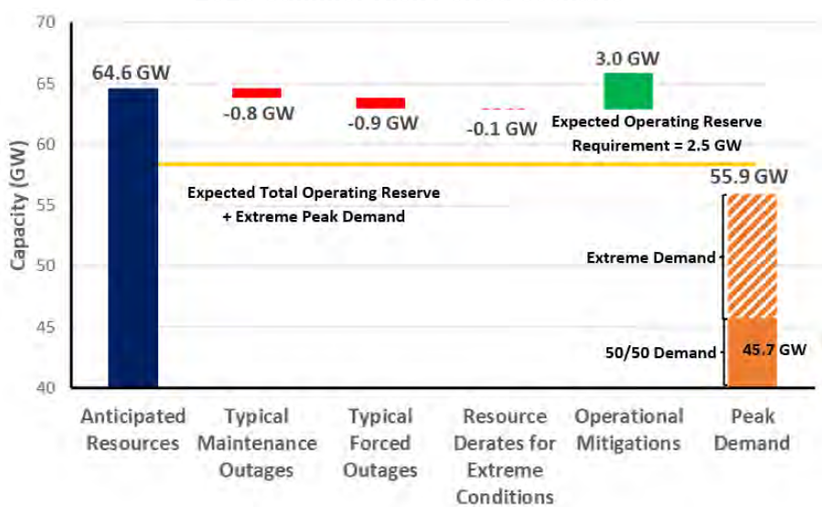
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

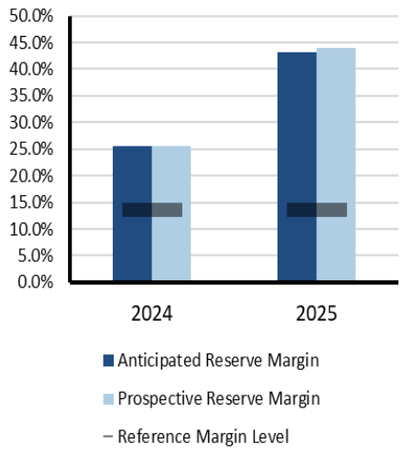
Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

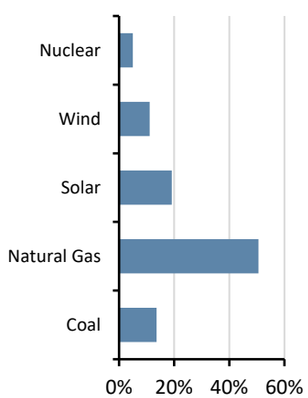
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

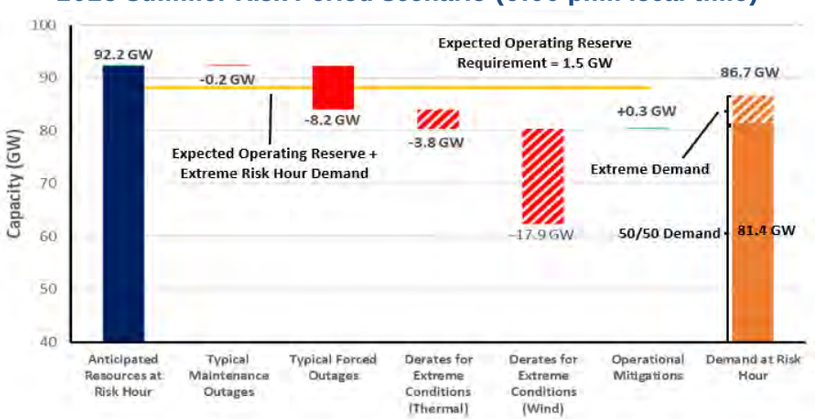
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports



WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

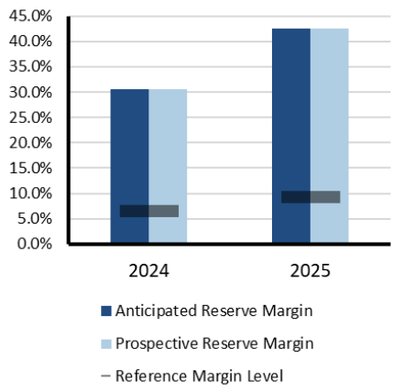
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

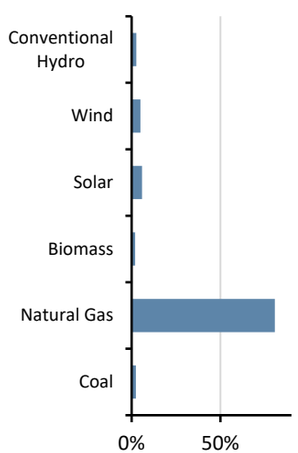
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

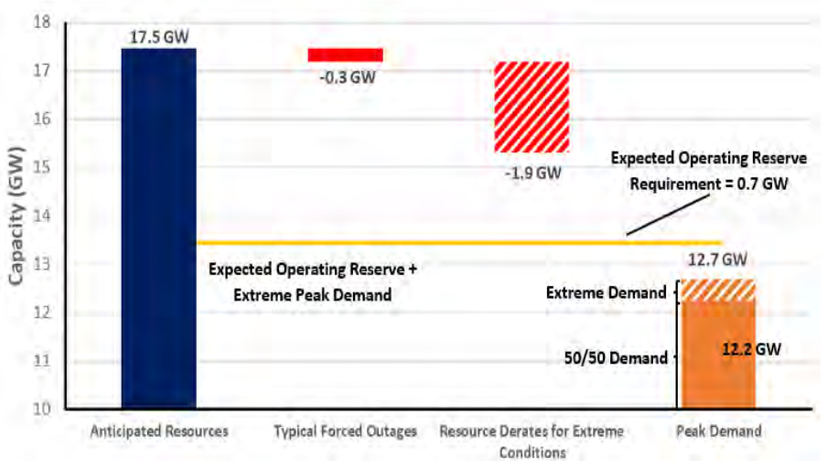
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

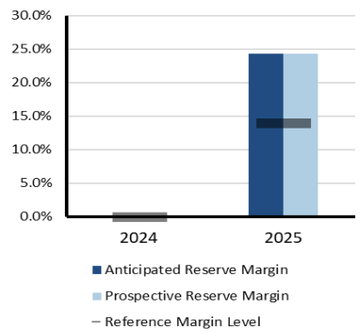
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

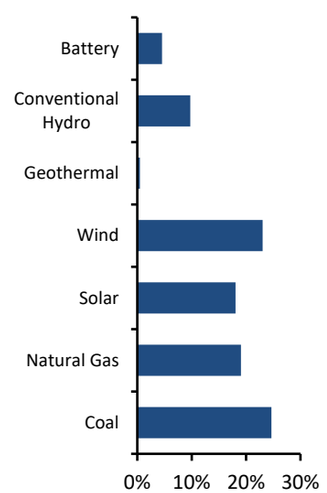
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

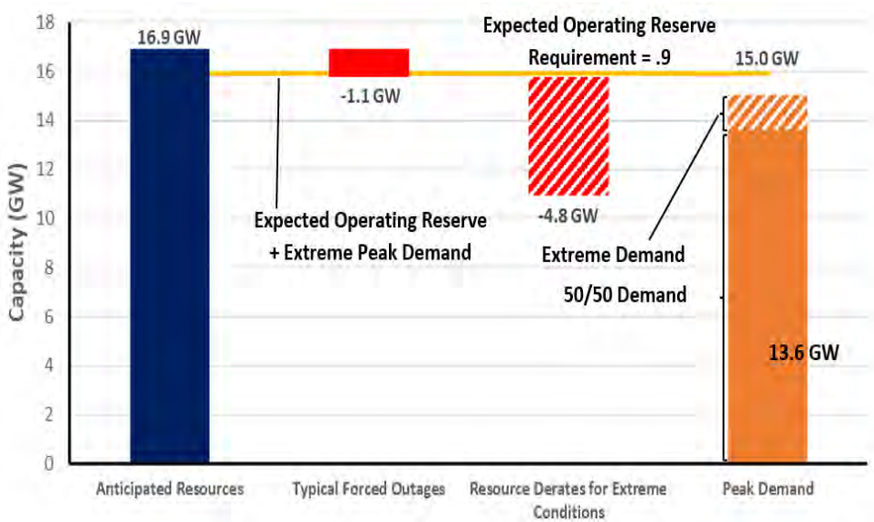
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

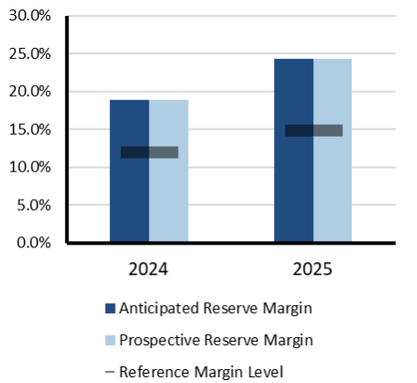
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

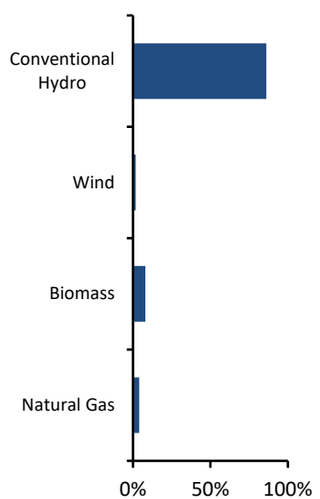
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

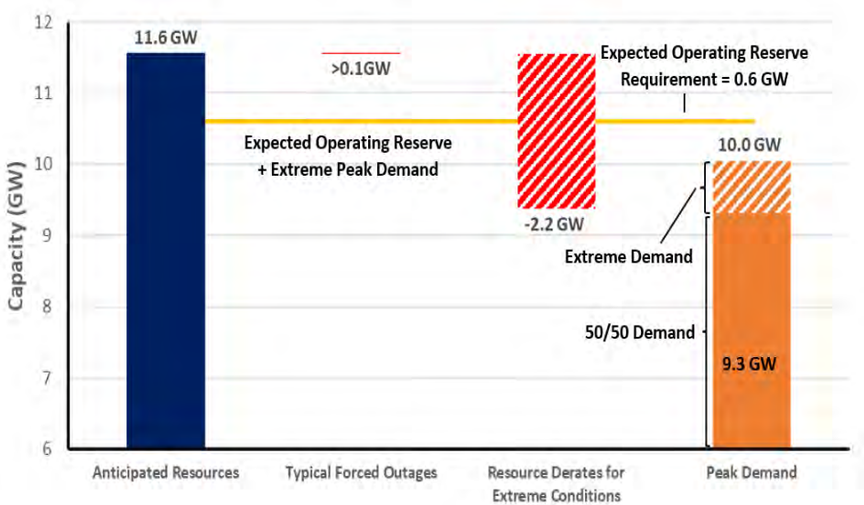
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA*.

Highlights

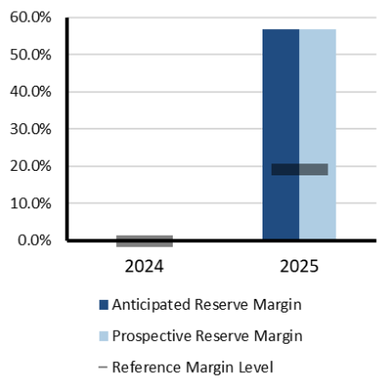
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

Risk Scenario Summary

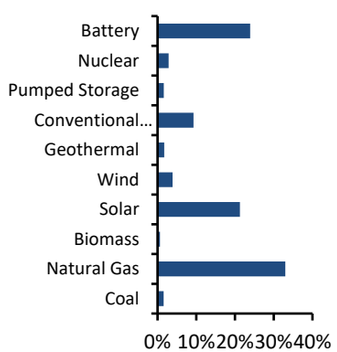
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

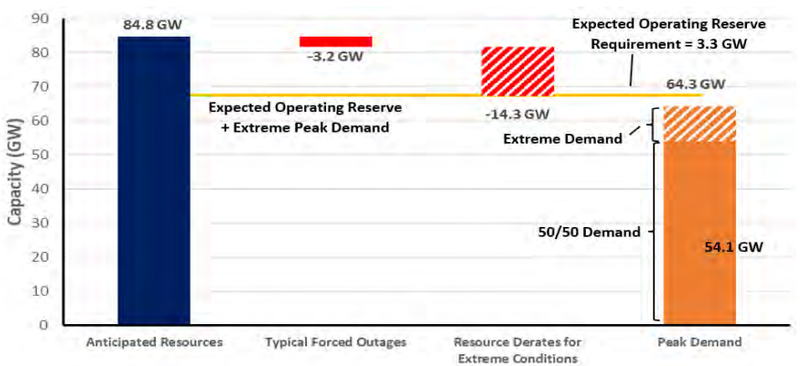
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages



WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

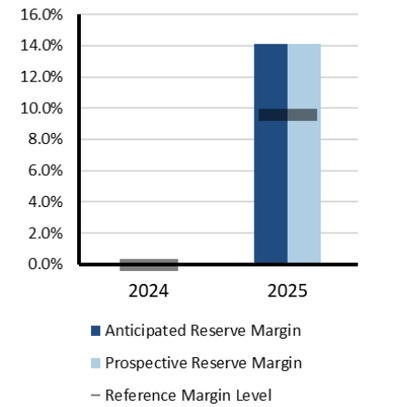
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

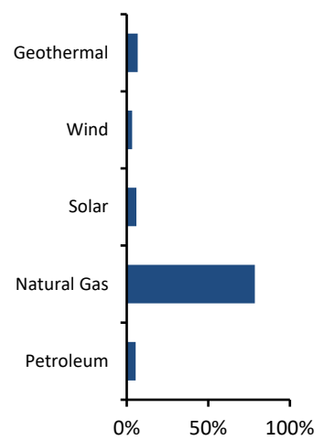
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

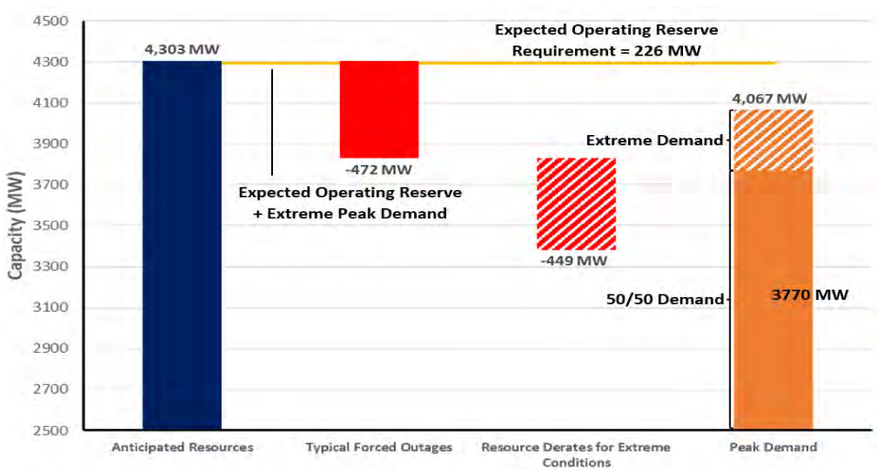
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA*.

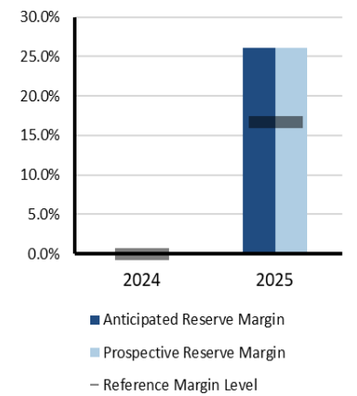
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

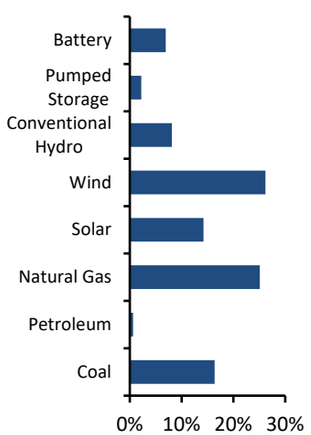
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

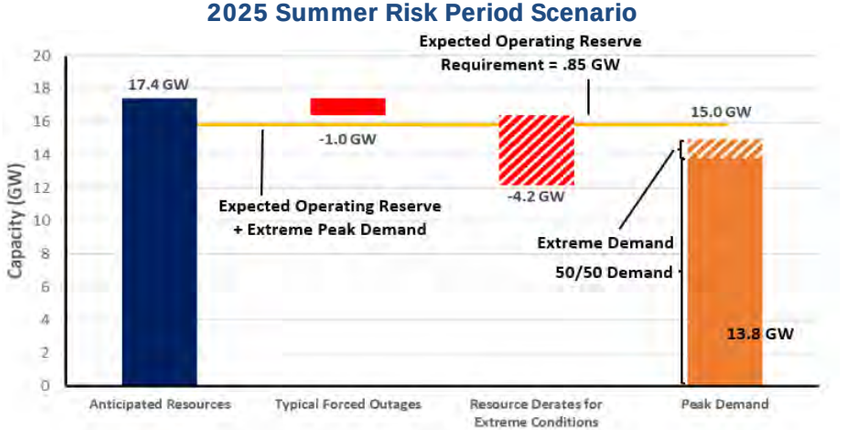


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA.*

Highlights

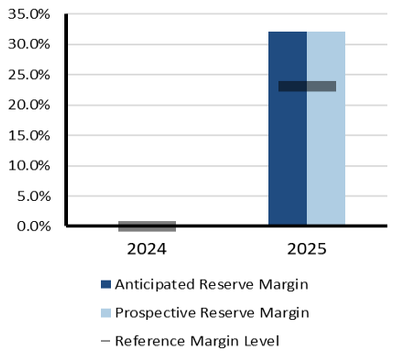
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

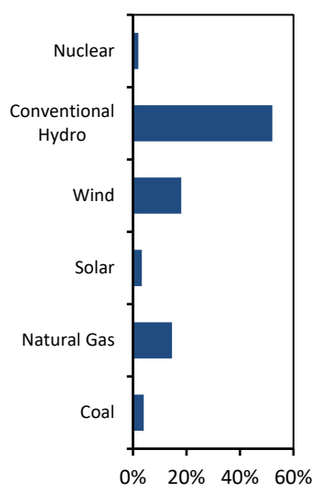
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

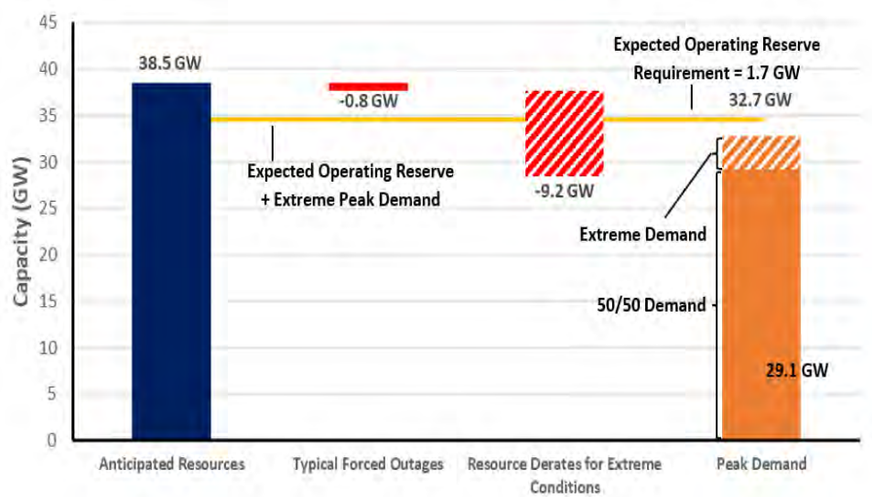
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

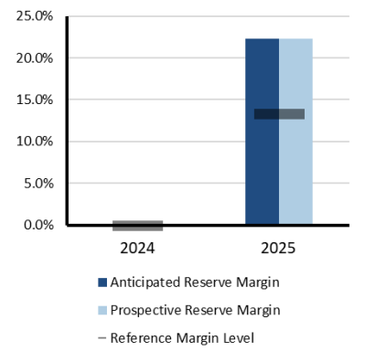
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

Risk Scenario Summary

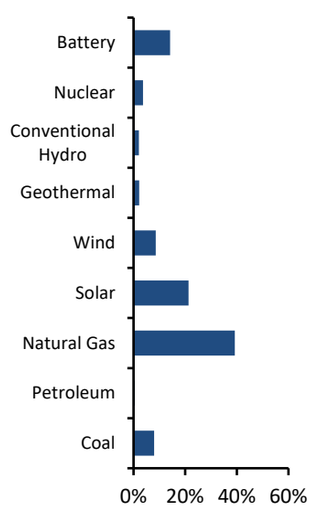
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

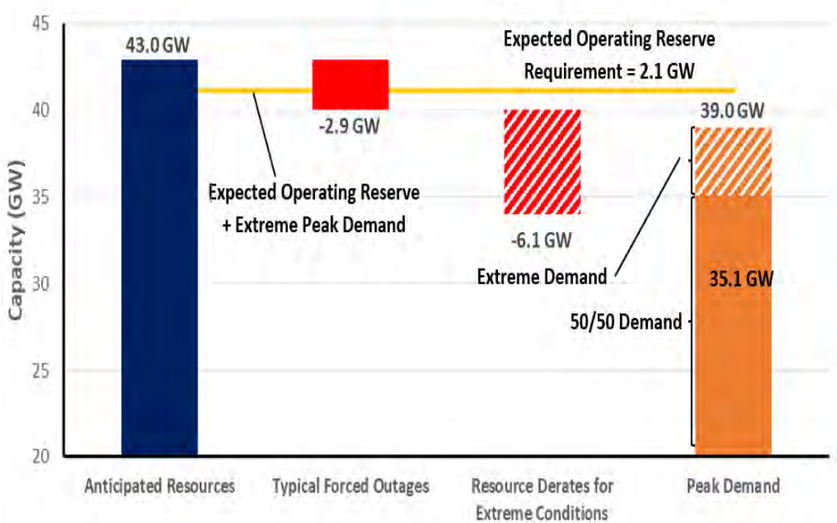
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

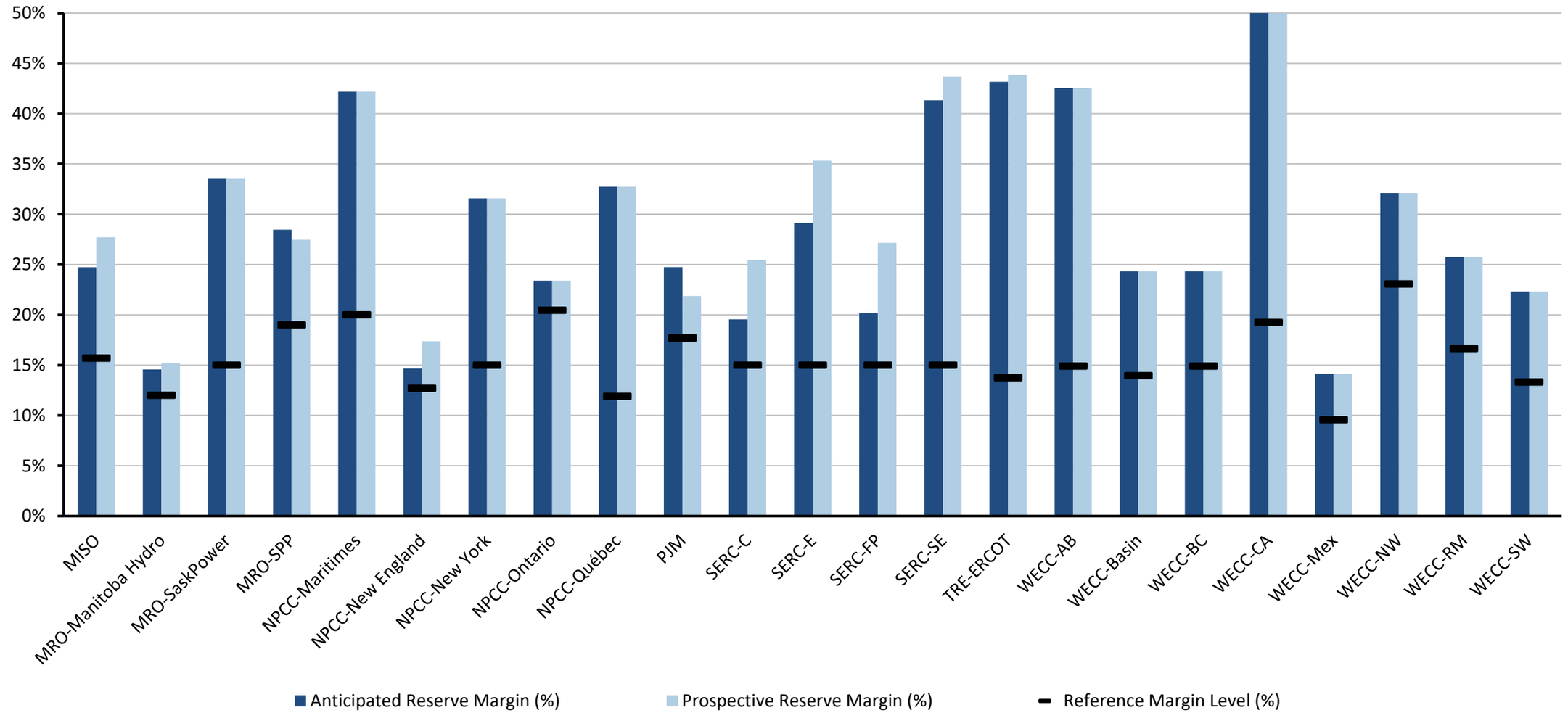


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

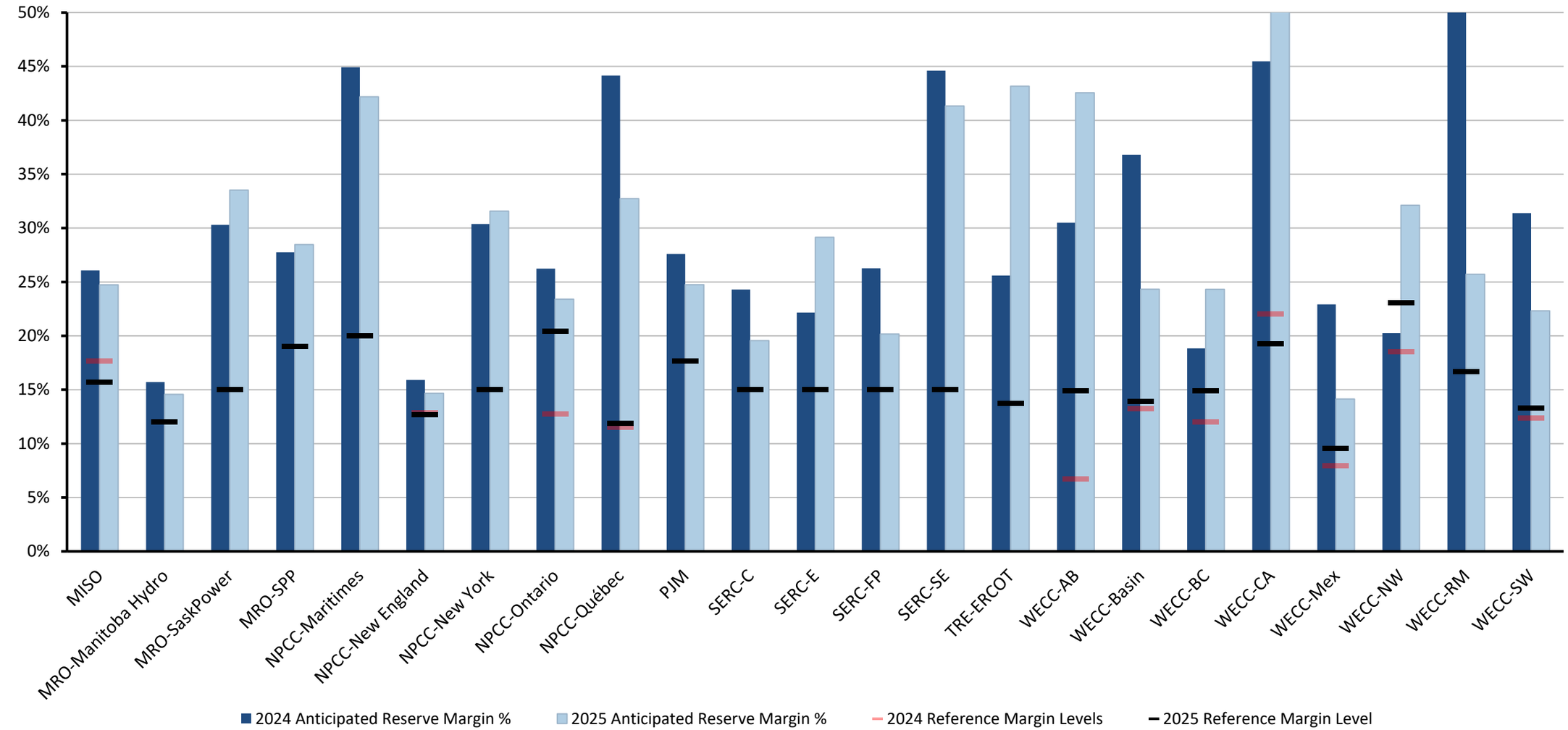


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

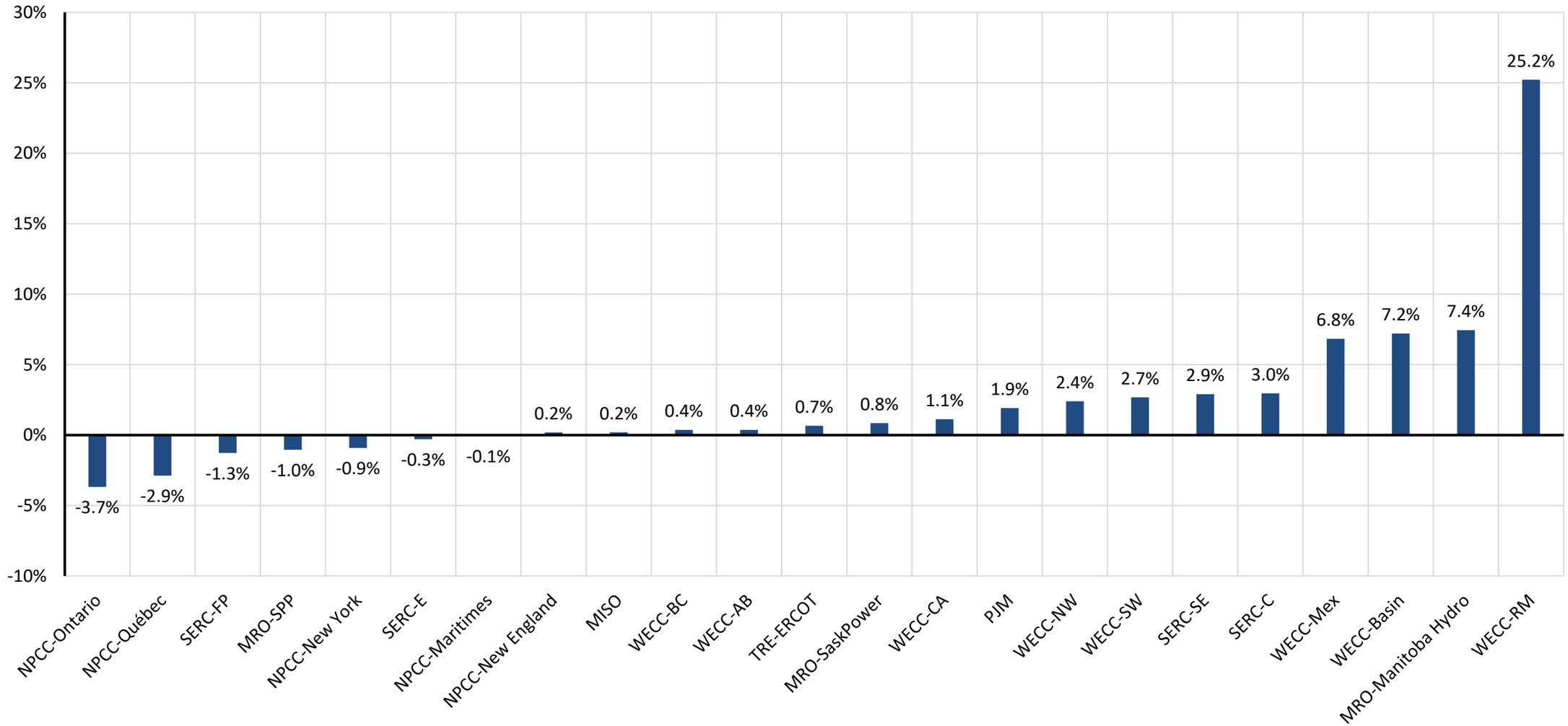


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	**175,081**	**34,774**	**20%**	**142,014**	**86,170**	**61%**	**101,959**	**65,290**	**64%**	**36,311**	**32,298**	**89%**

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Planning Resource Auction
Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
—
Fall
$91.60 (North/Central)
$74.09 (South)
—
Winter
$33.20
—
Spring
$69.88
—
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

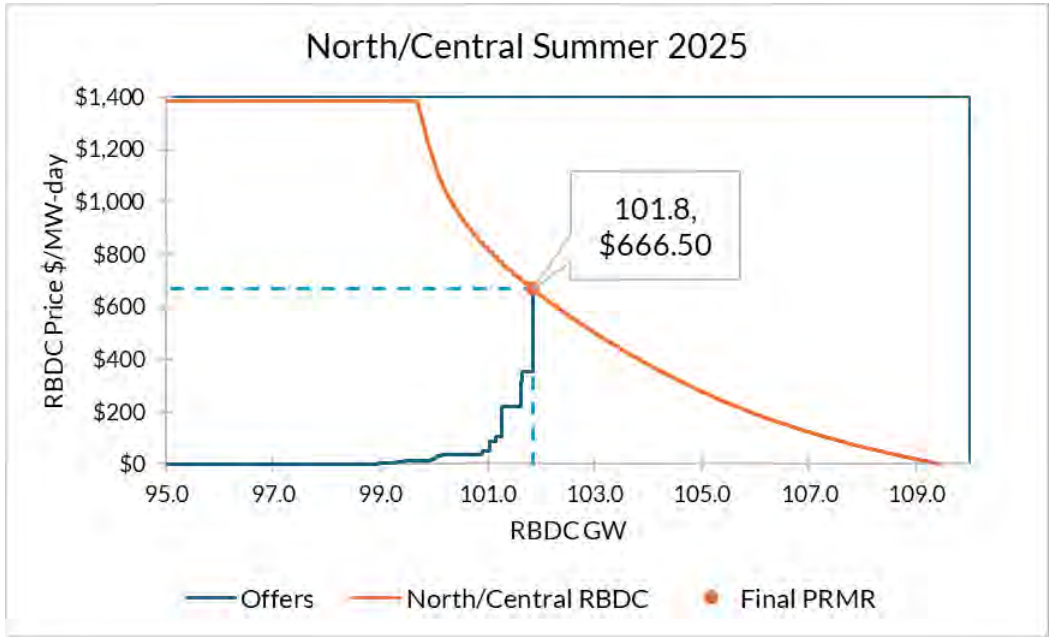
- Delivers competitive prices aligned with seasonal risks and tightening surplus
    - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
    - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

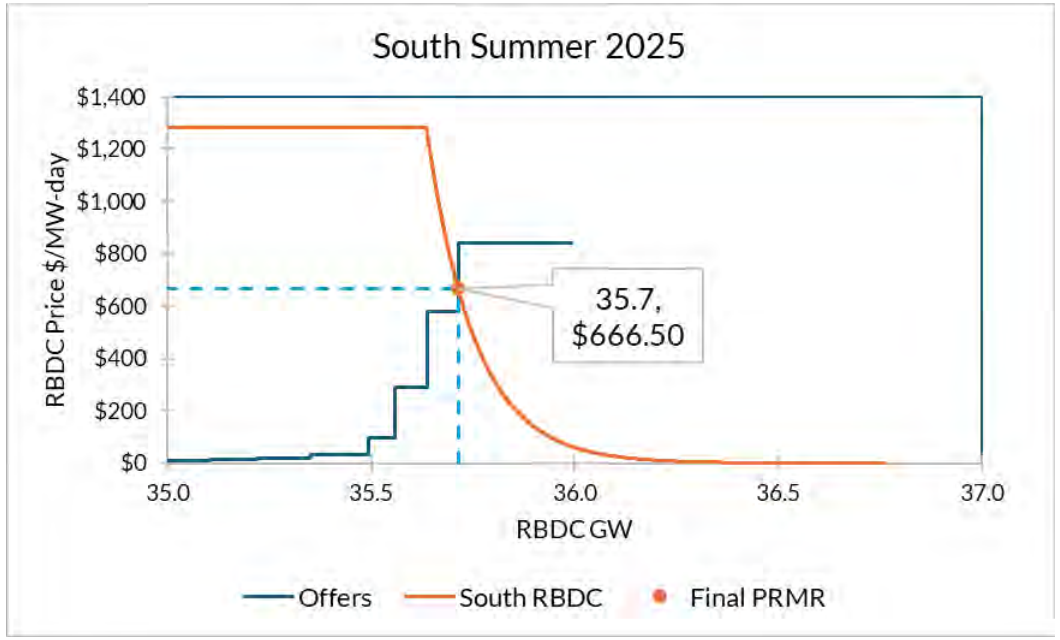
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

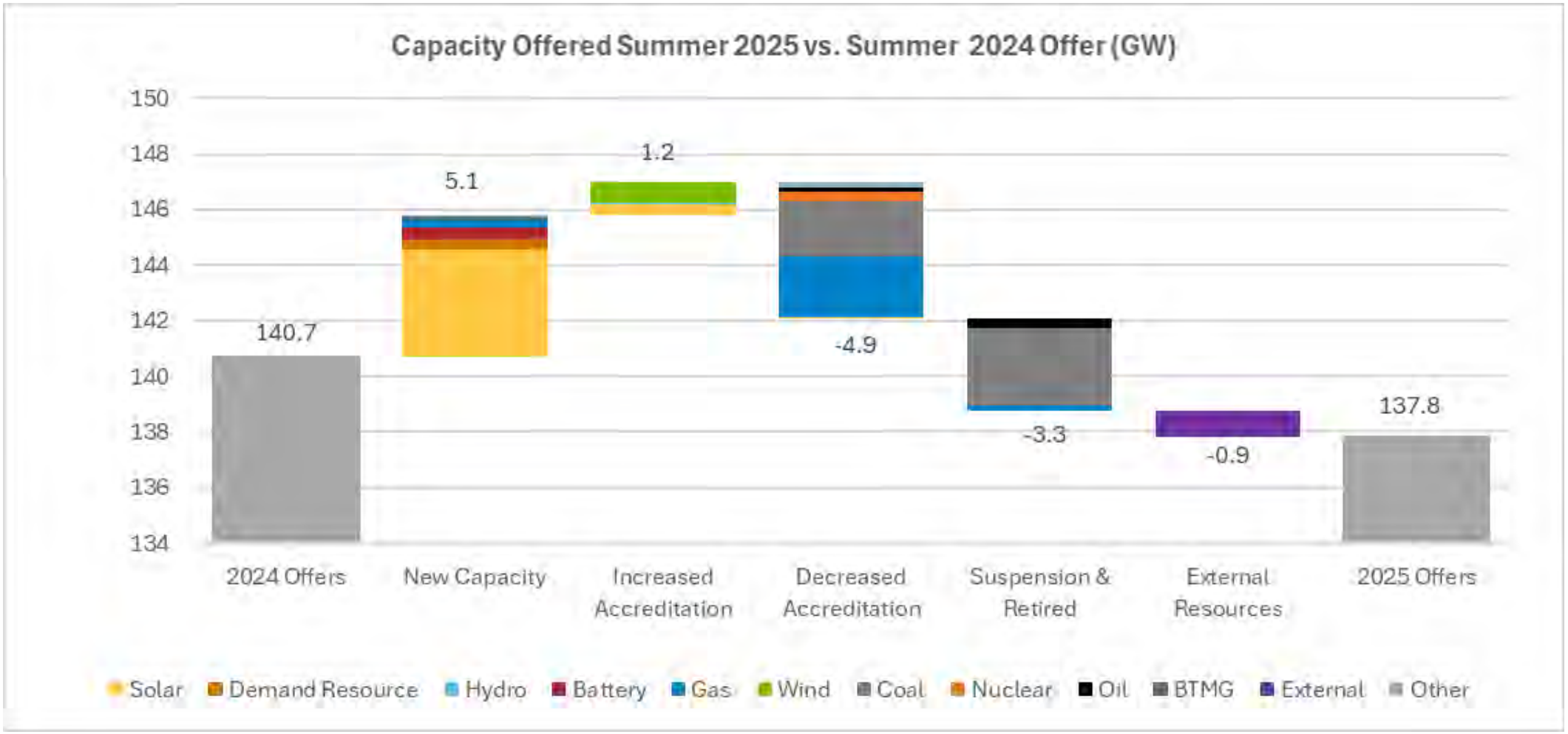
MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88 ***Annualized*** **$217** (North/Central) **$212** (South)

PRM: Planning Reserve Margin

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

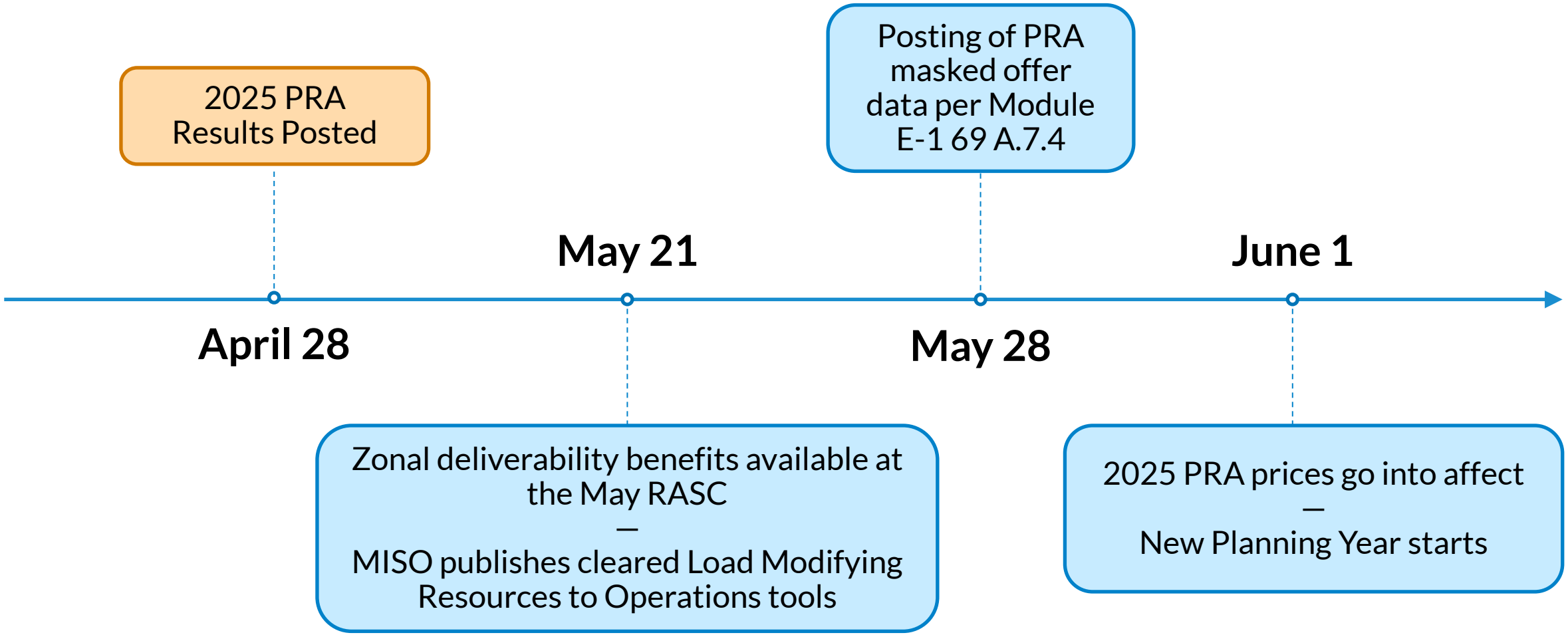
- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement Direct Loss of Load (DLOL)-based accreditation
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Next Steps


2025 PRA Results Posted
April 28
May 21
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
Posting of PRA masked offer data per Module E-1 69 A.7.4
May 28
June 1
2025 PRA prices go into affect
—
New Planning Year starts

Appendix

Table of Contents

List of Acronyms	11
PRA Prices with Resource Adequacy Zone map	12
Resource Offer by Subregion	13-14
Reliability-Based Demand Curves by Season	15-17
Seasonal Results by Zone	18-21
Seasonal Supply Offered and Cleared Comparison Trend	22-25
Seasonal Auction Clearing Price, Offer Thresholds, and CONE Prices	26
Historical Seasonal Auction Clearing Price Comparison	27-30
2025/26 Seasonal Offered Capacity & PRMR and Cleared Capacity, Exports & Imports Maps	31-34
2025 PRA relative to 2024 OMS-MISO Survey	35
Coincident Peak Forecast	36
Planning Reserve Margin (%)	37
Wind Effective Load Carrying Capacity (%)	38
Seasonal Resource Adequacy Fulfillment	39
Wind and Solar Cleared SAC	40
Seasonal Cleared ZRC by Fuel Type	41-42
Planning Resource Mix Trend	43
PRA Seasonally Cleared Load Modifying Resources Comparison	44

Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

UCAP: Unforced Capacity

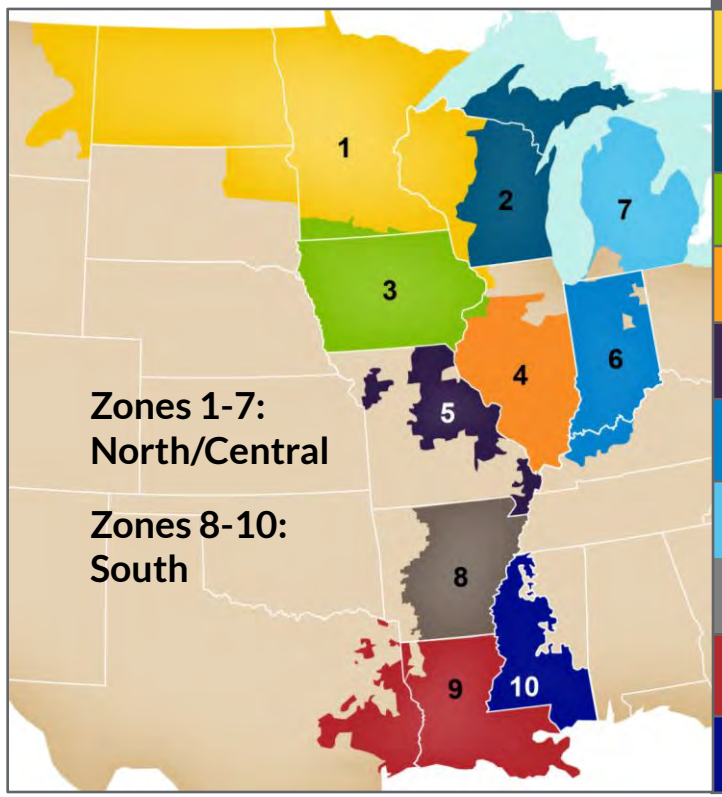
ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

2025 PRA Results

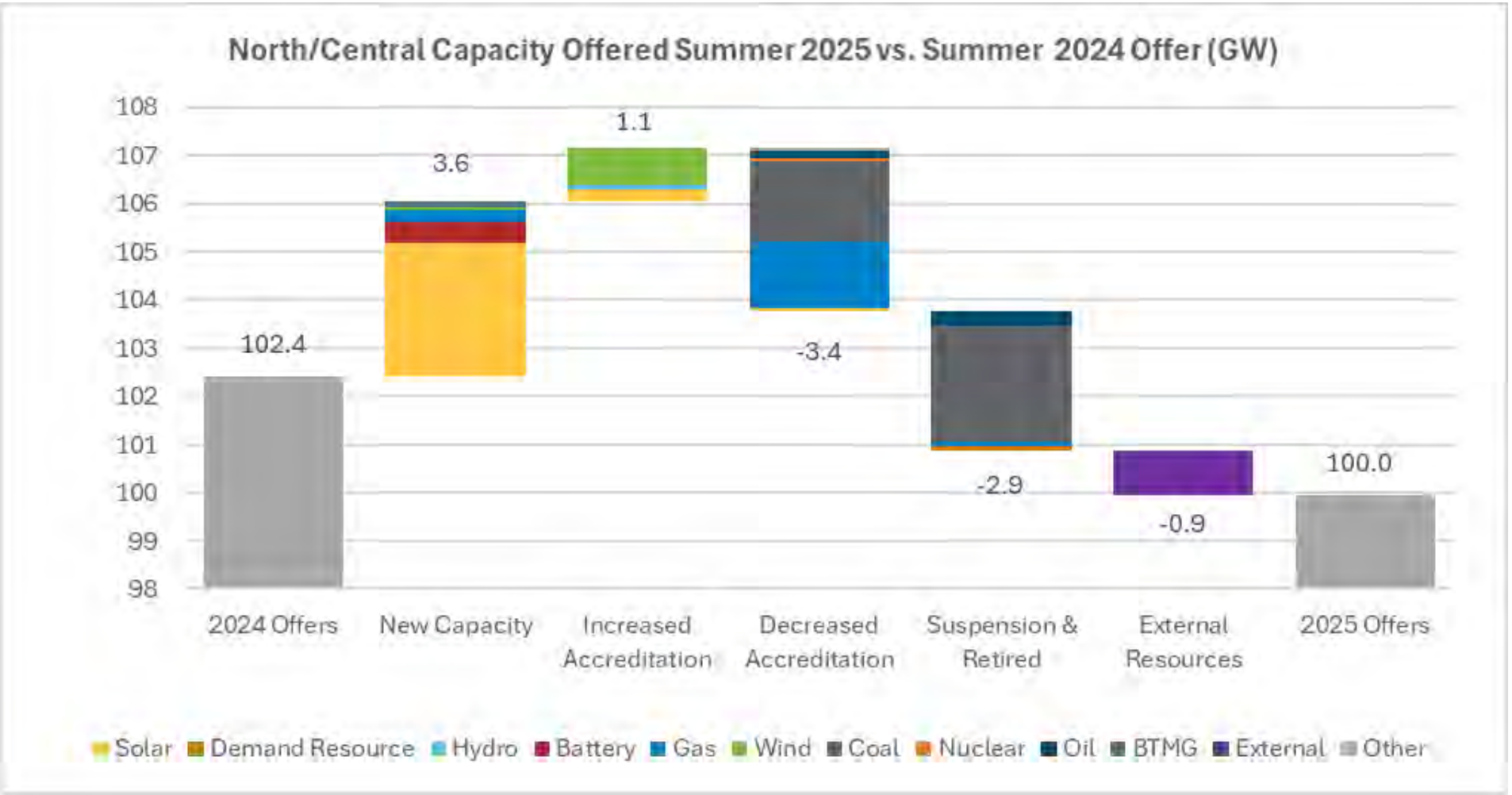
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

Annualized
$217 (North/Central)
$212 (South)

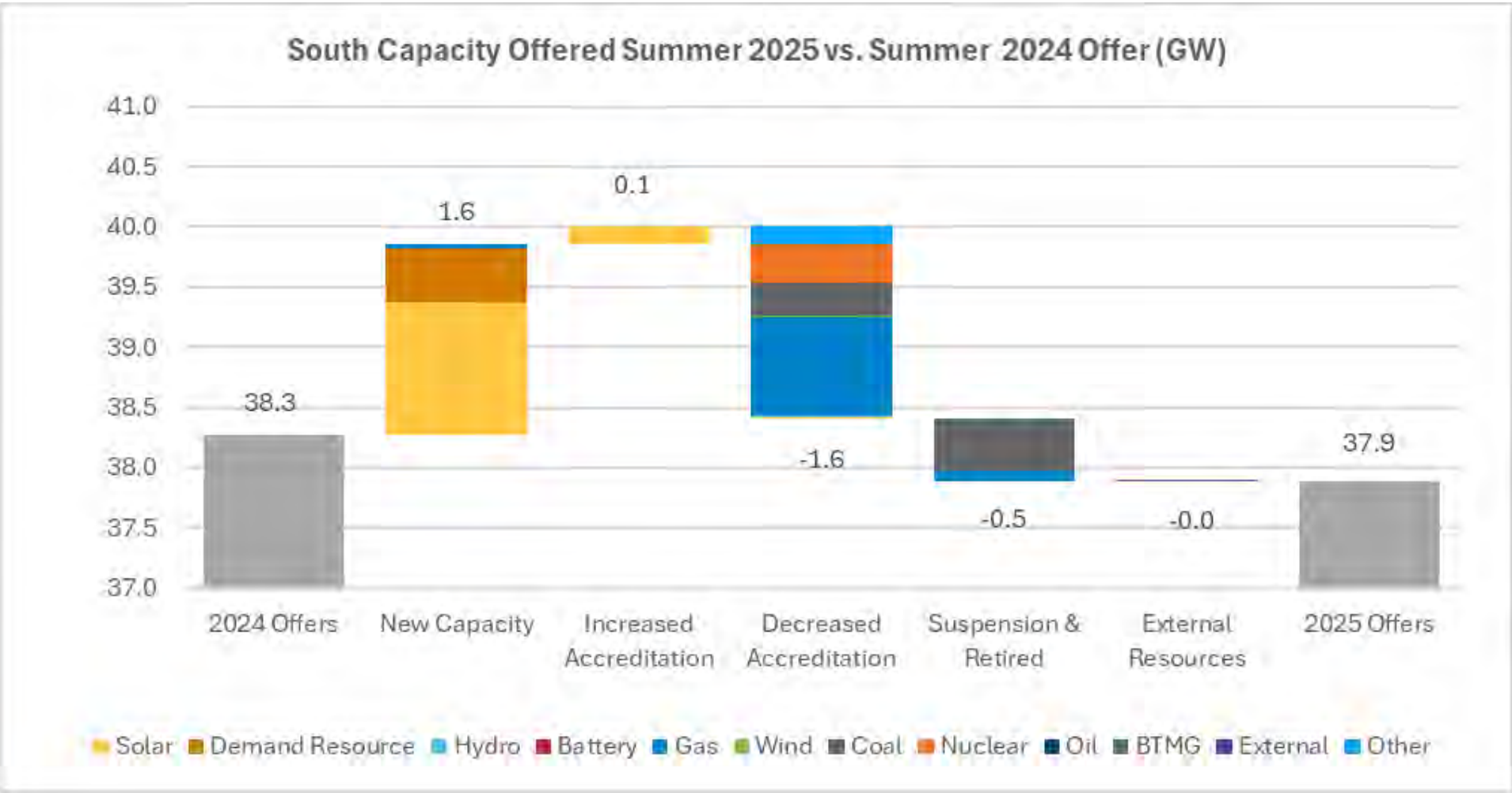
For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

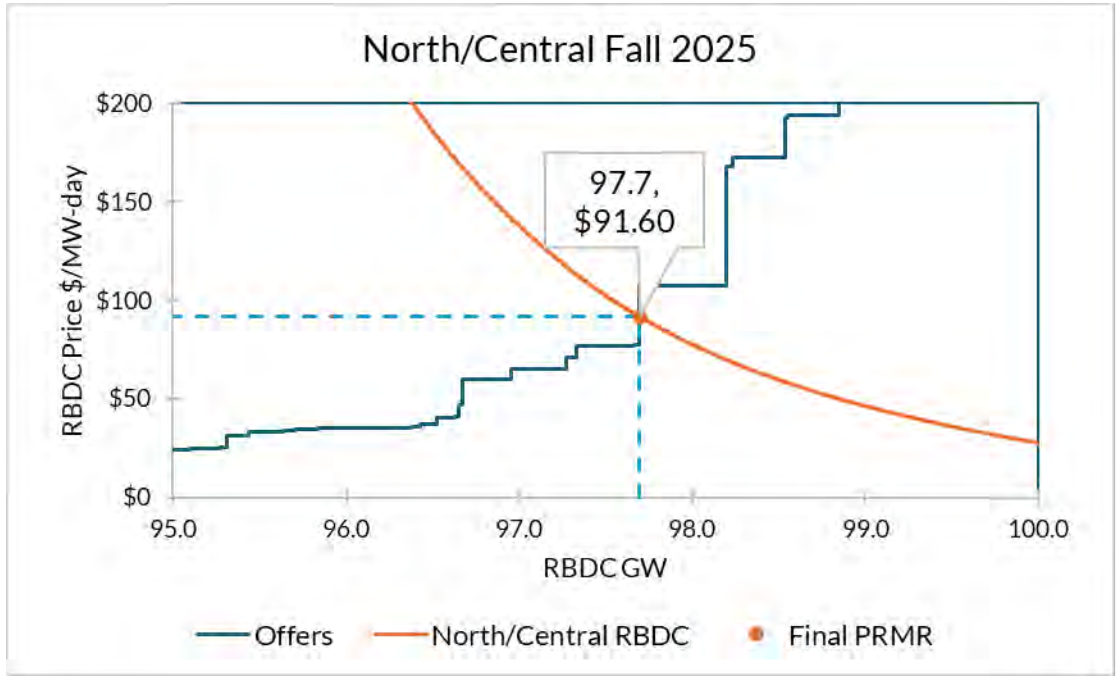
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

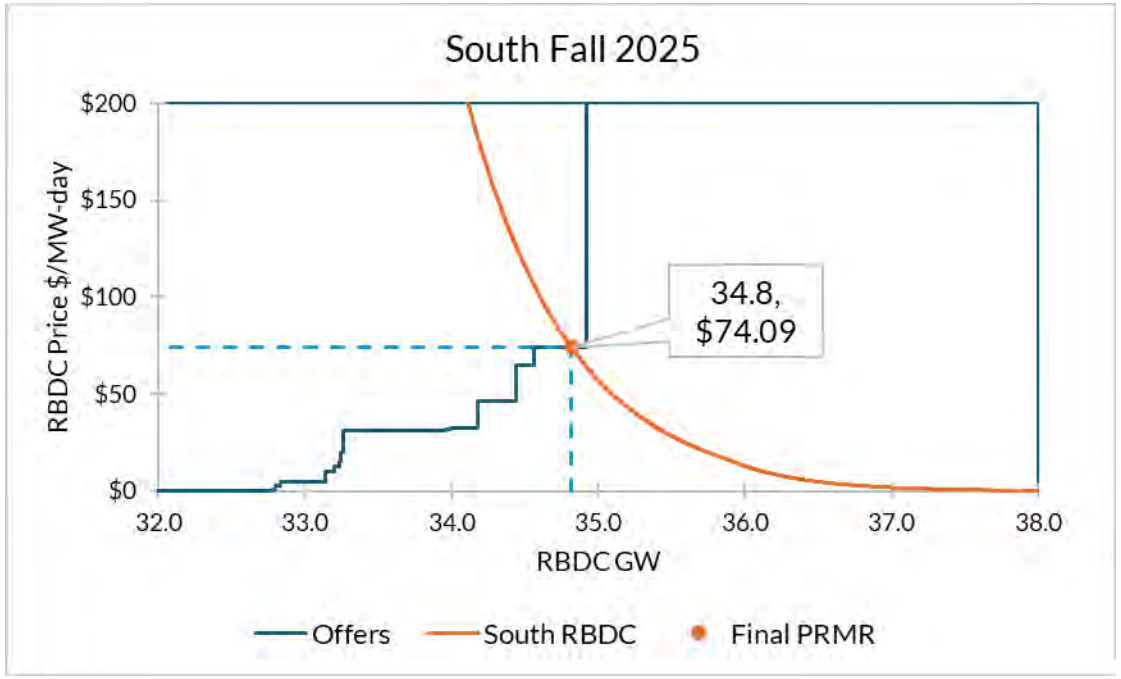
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

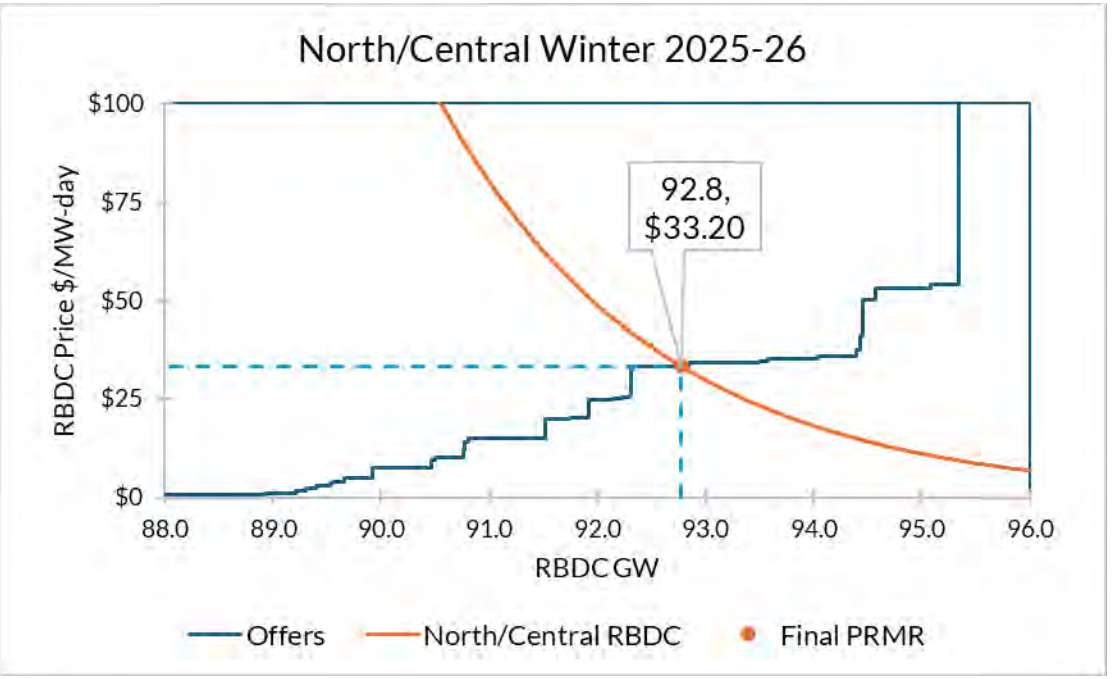
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

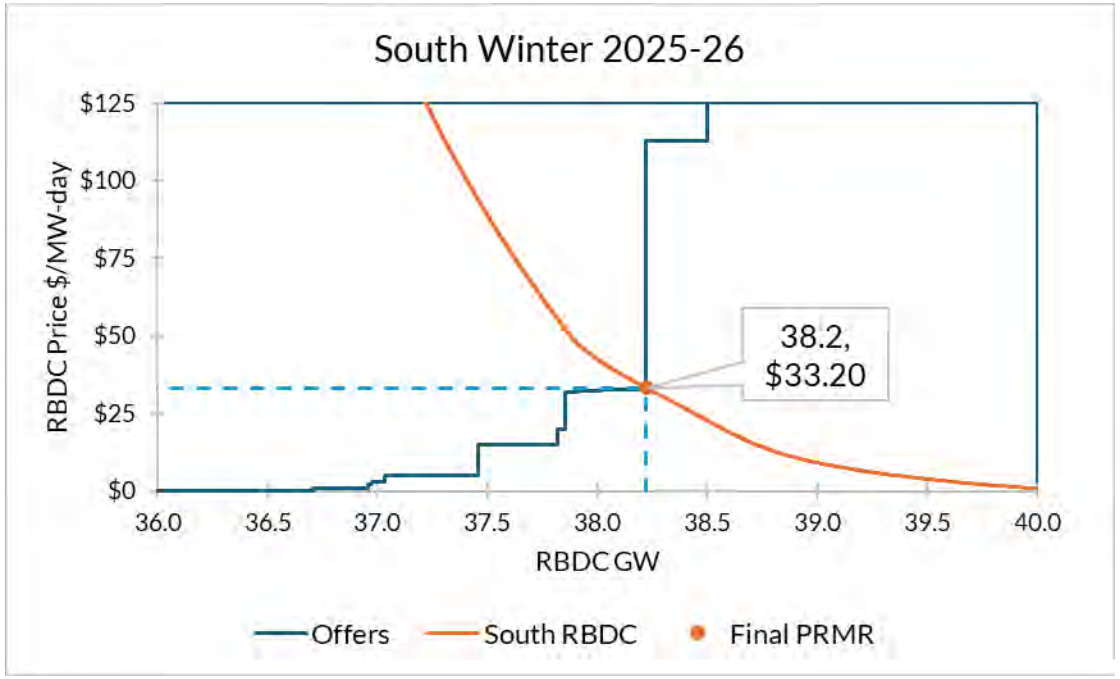




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal resource in the South sets the price in that subregion
- In fall season, "effective" margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

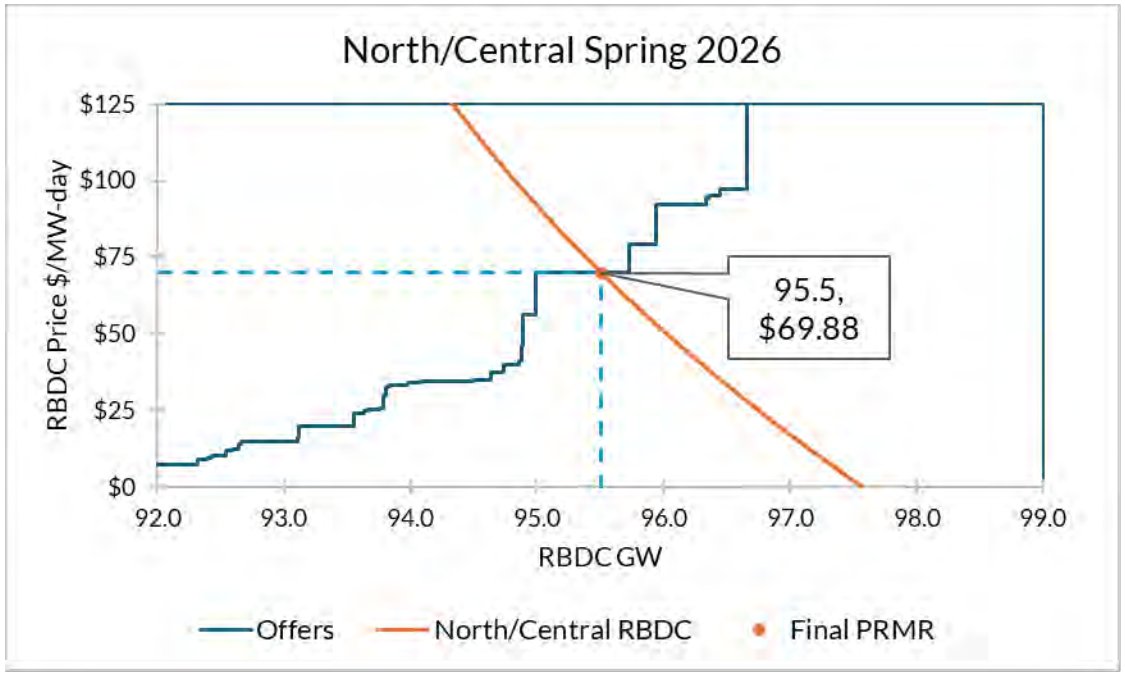
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

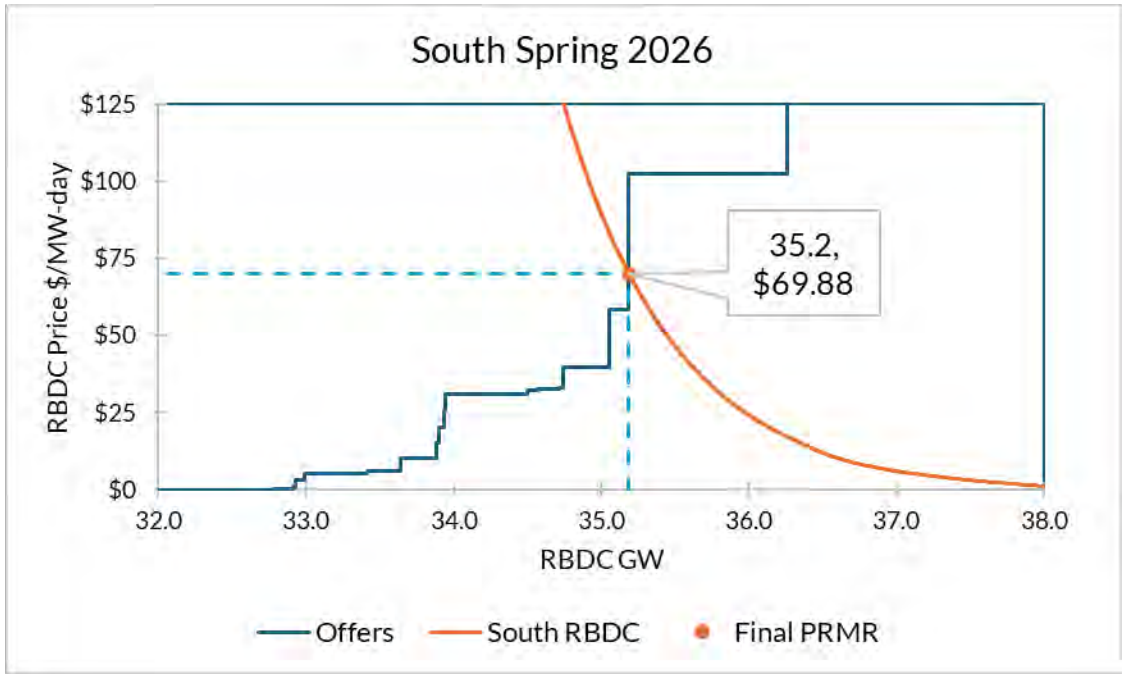




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, "effective" margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $69.88
  - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summer 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Summer 2023**	**Summer 2024**	**Summer 2025**	**Summer 2023**	**Summer 2024**	**Summer 2025**
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Fall 2023**	**Fall 2024**	**Fall 2025**	**Fall 2023**	**Fall 2024**	**Fall 2025**
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Spring 2024**	**Spring 2025**	**Spring 2026**	**Spring 2024**	**Spring 2025**	**Spring 2026**
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										
Summer 2025	$666.50										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



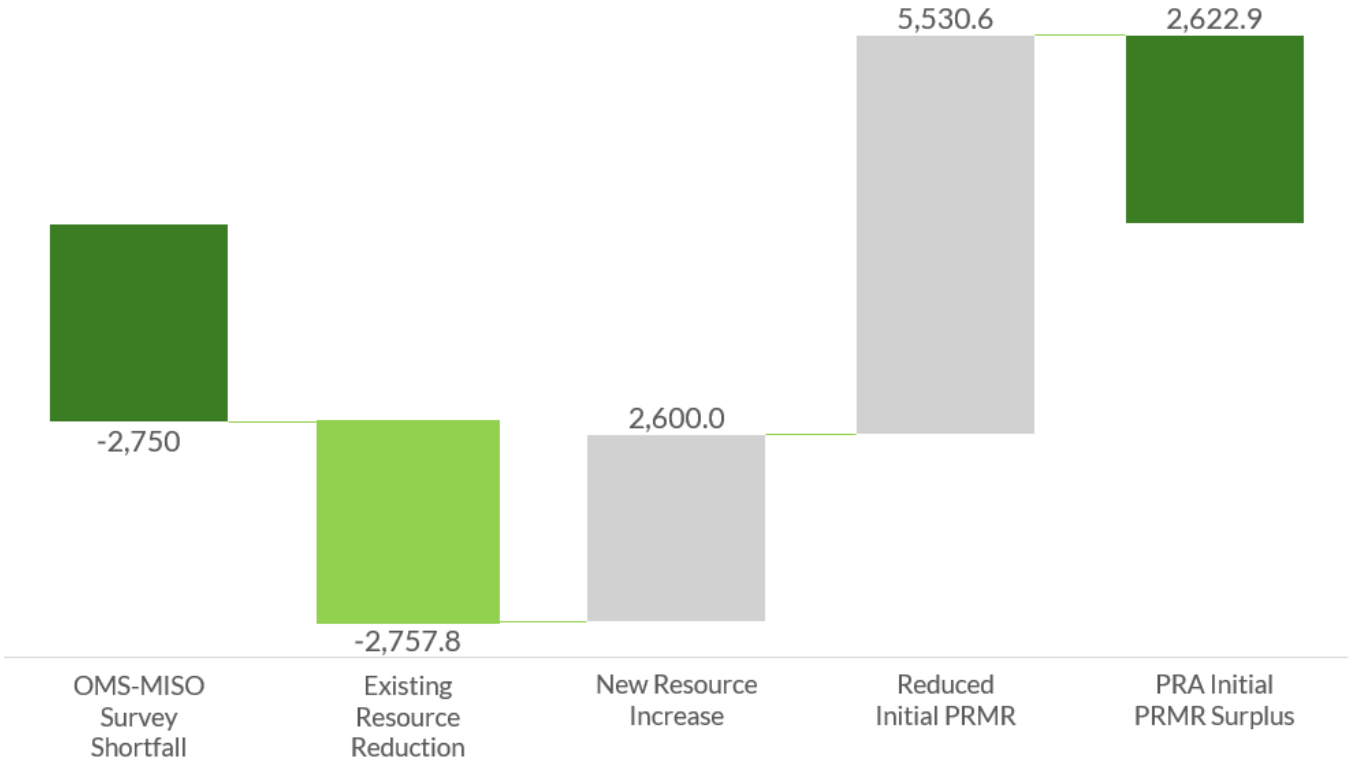
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

2024 OMS-MISO Survey Projection vs.
2025 PRA Actual PRMR Surplus (MW)

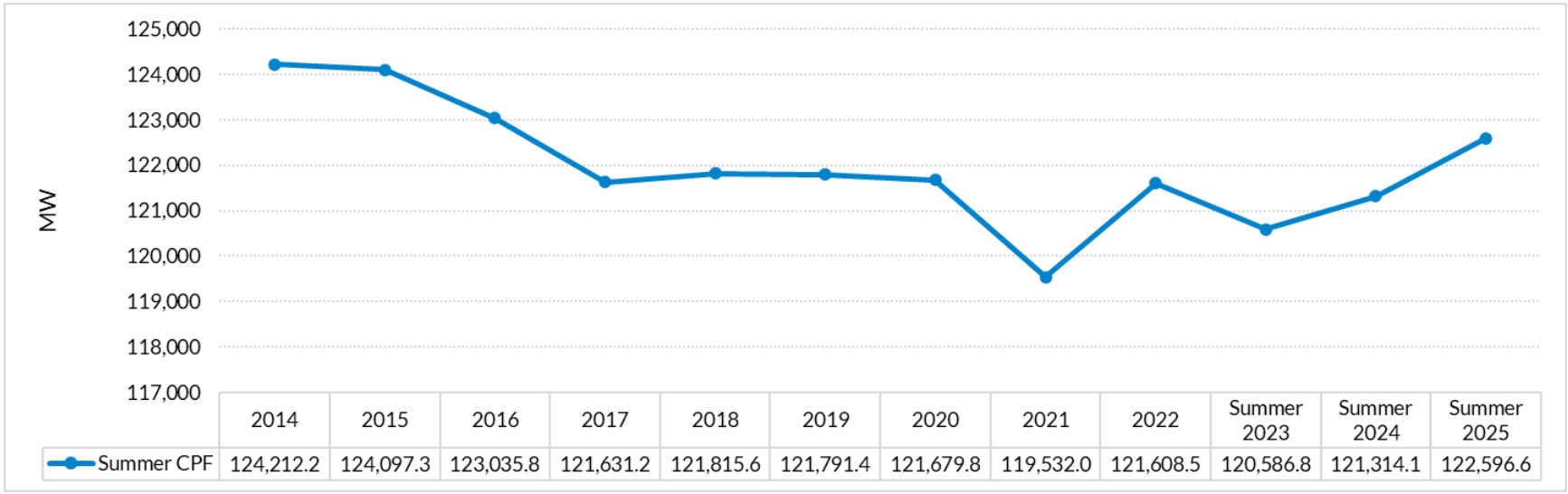


*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

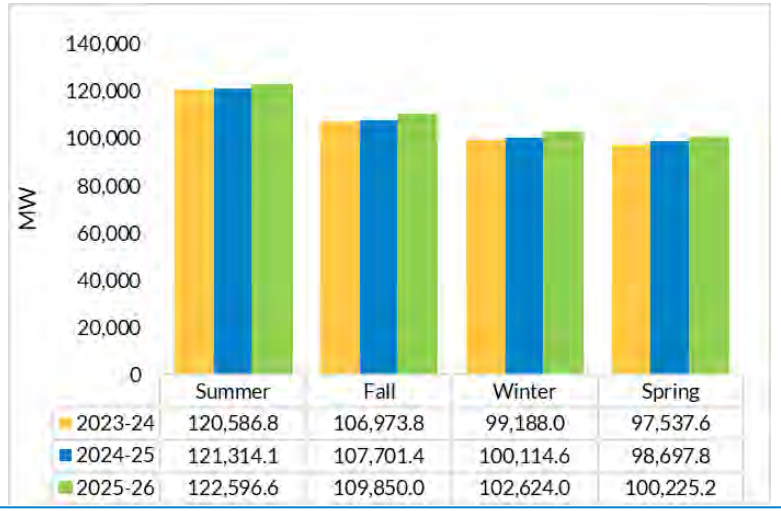
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6

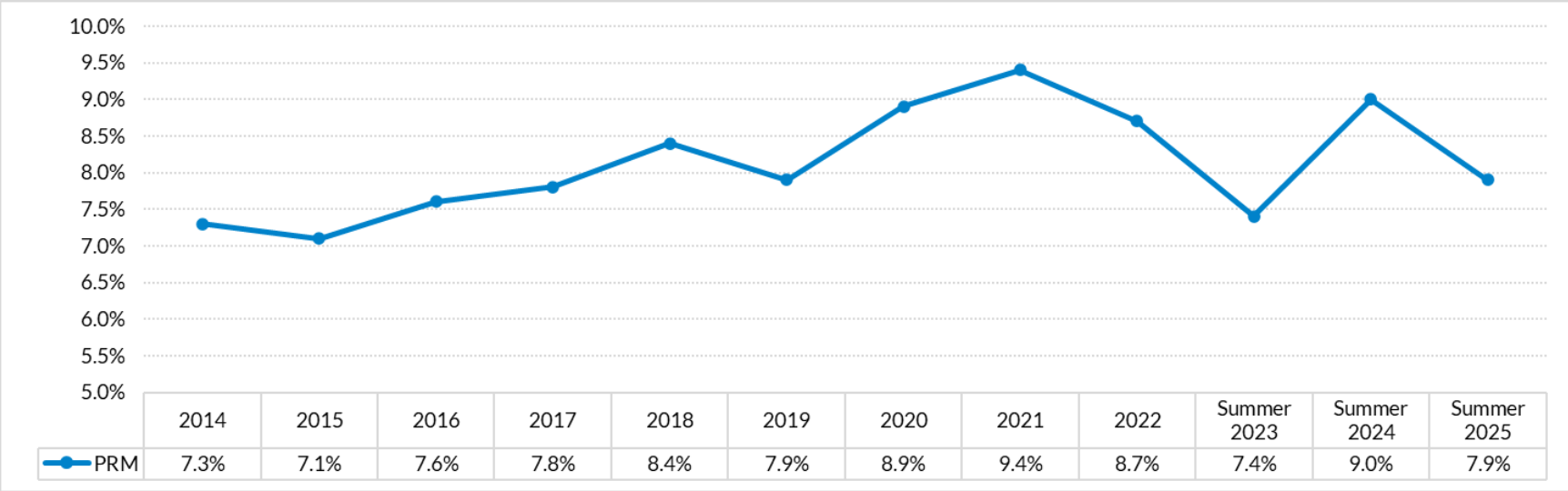


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

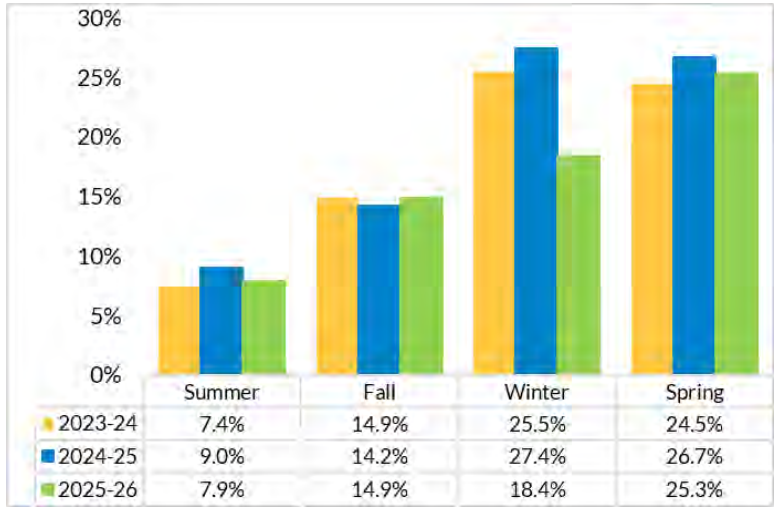
PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Planning Reserve Margin (%)

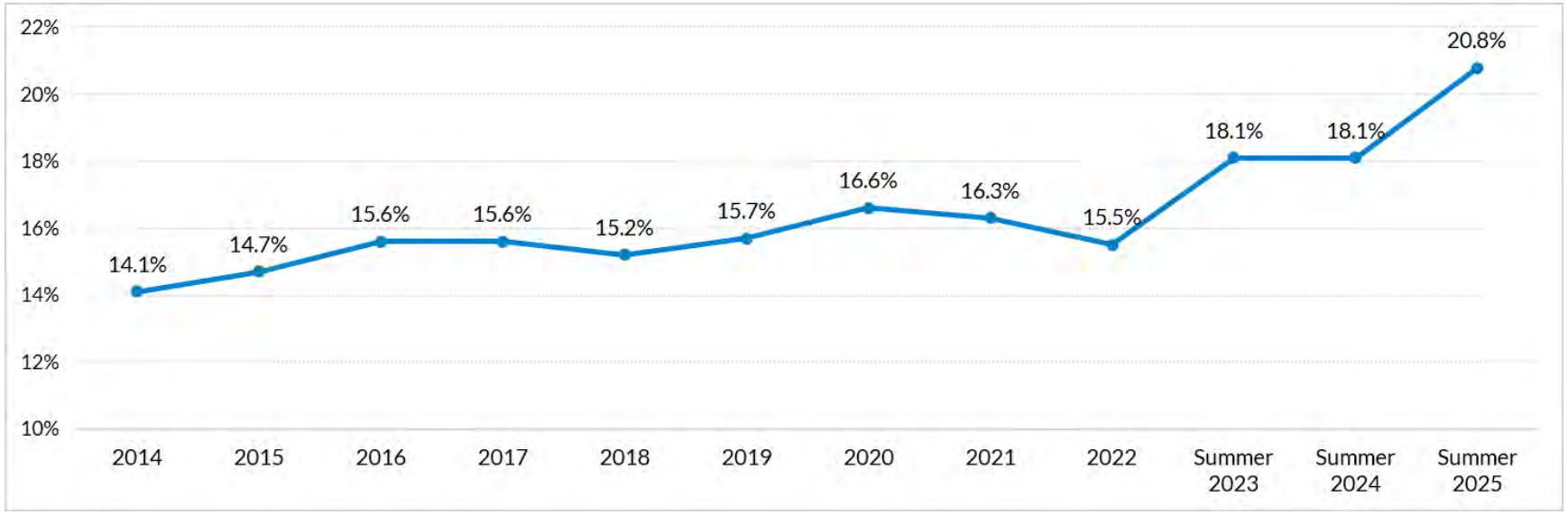


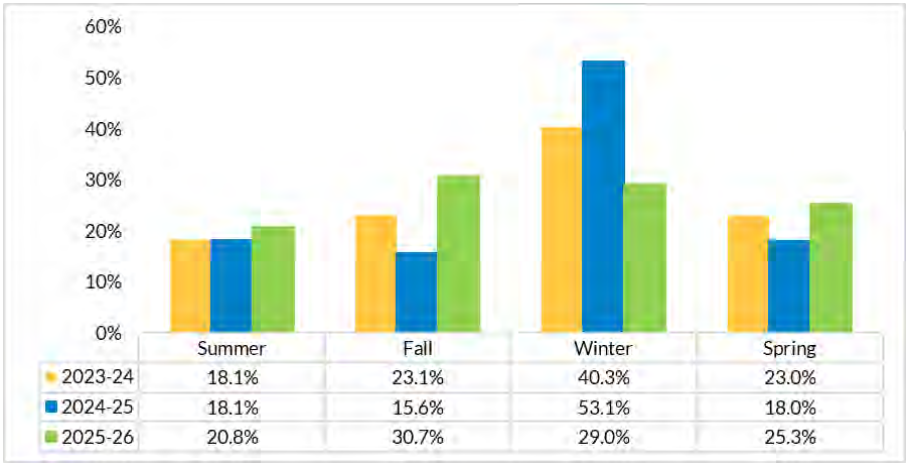
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)

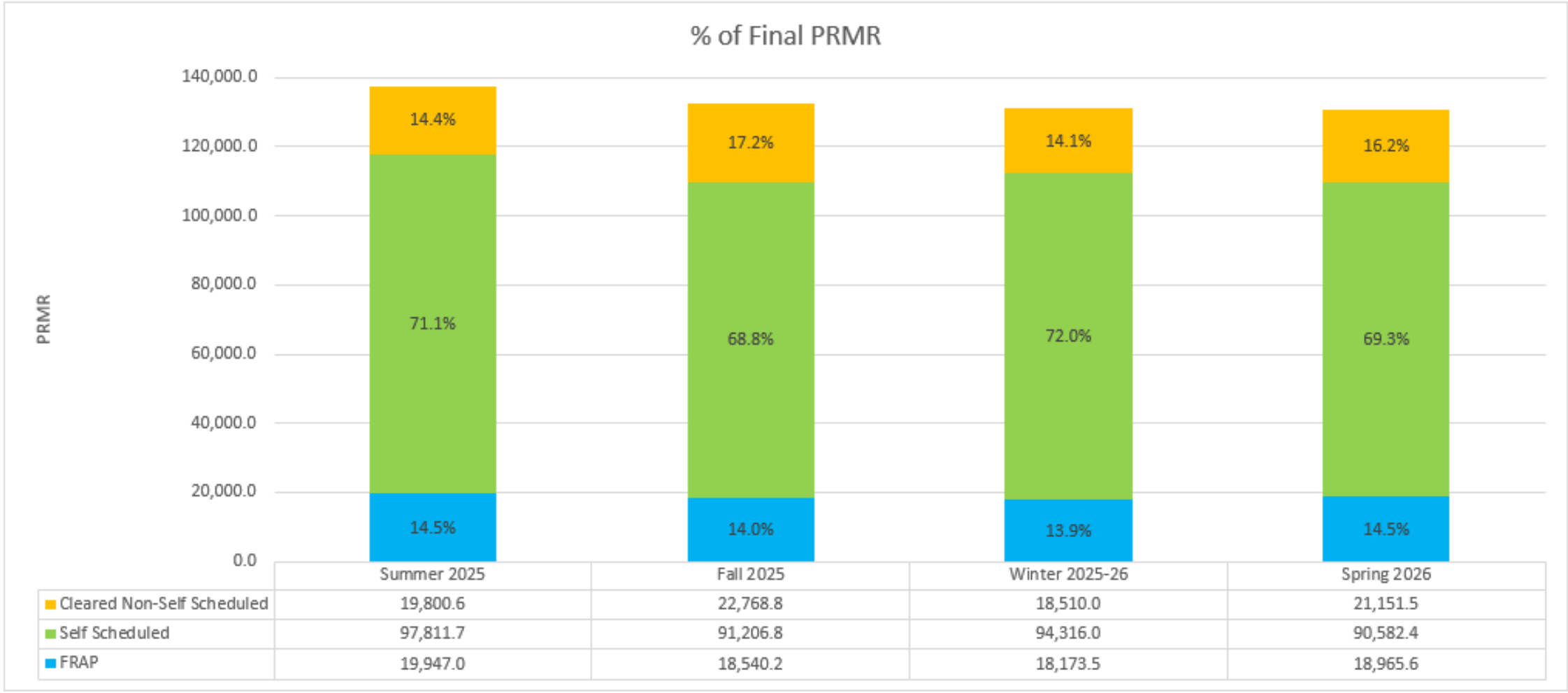




- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

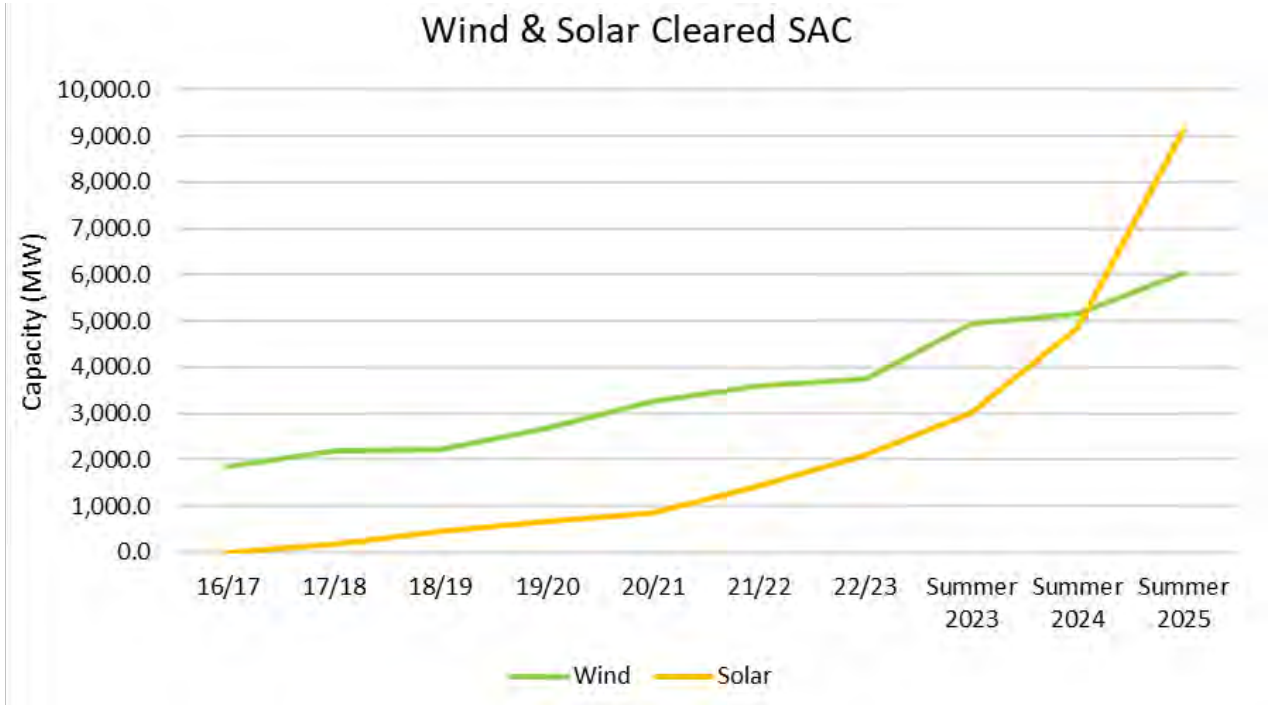


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

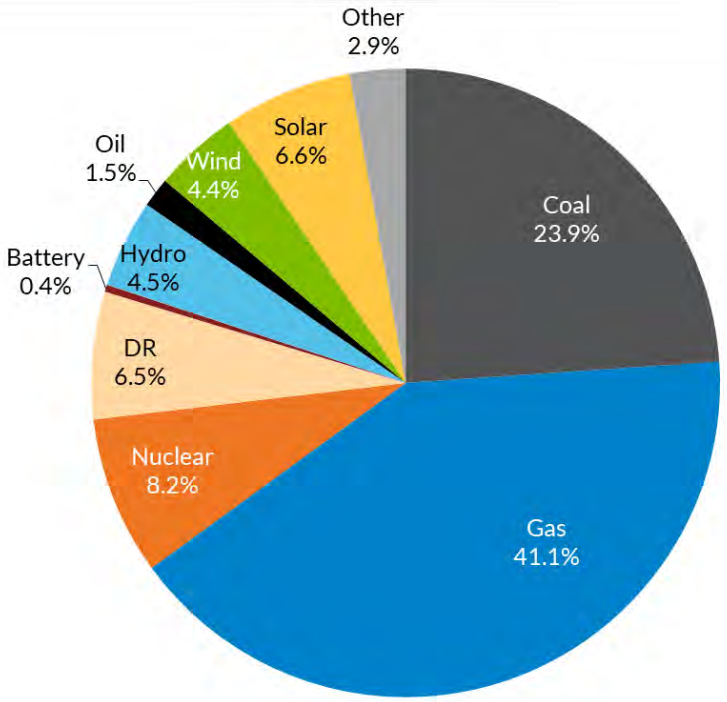
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

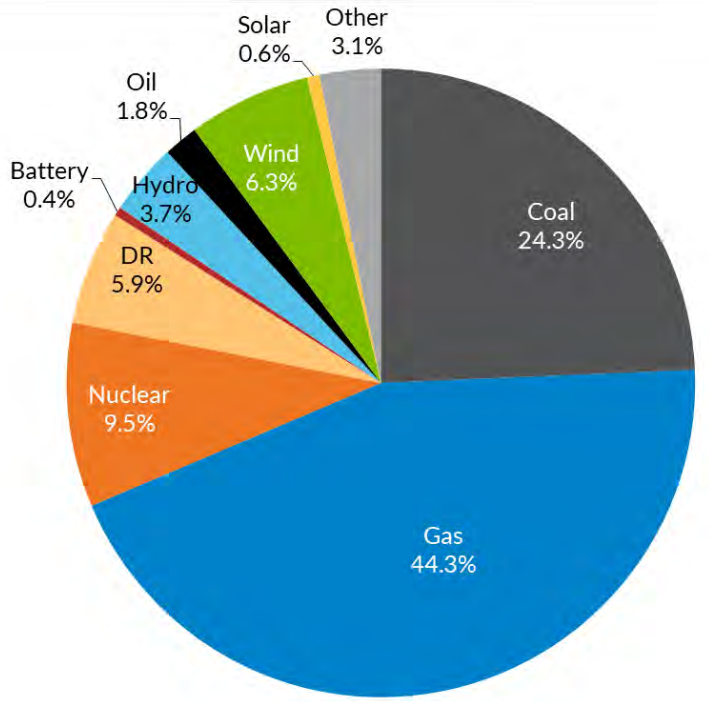
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

Winter 2025/26

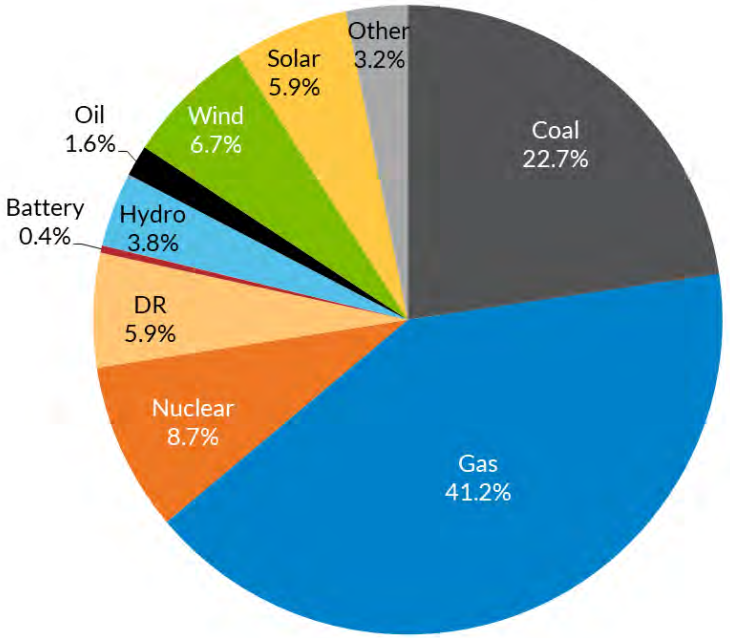


PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

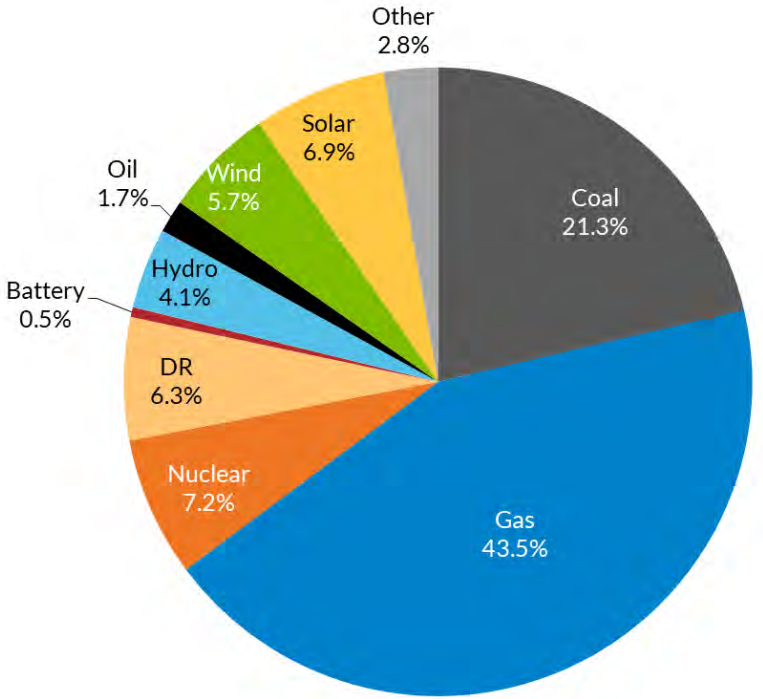
Fall 2025



MISO-Wide

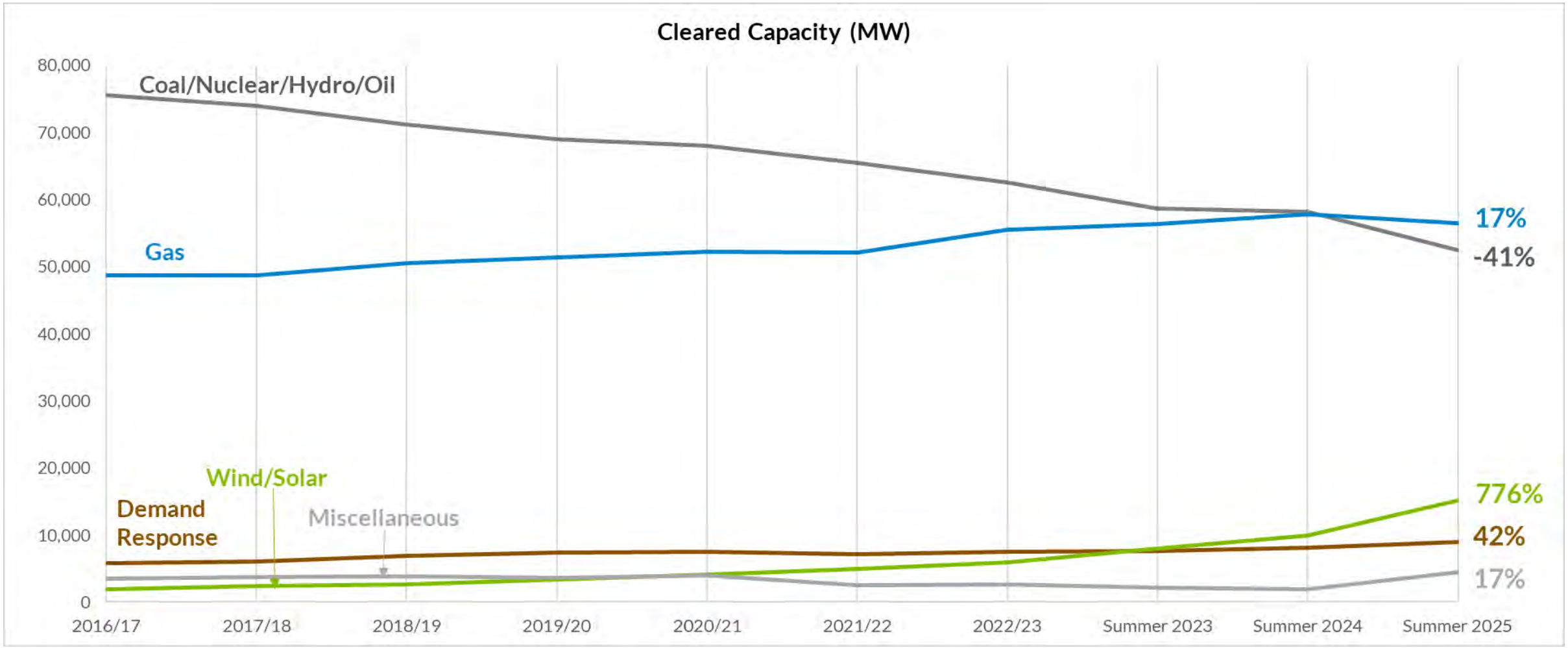
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026



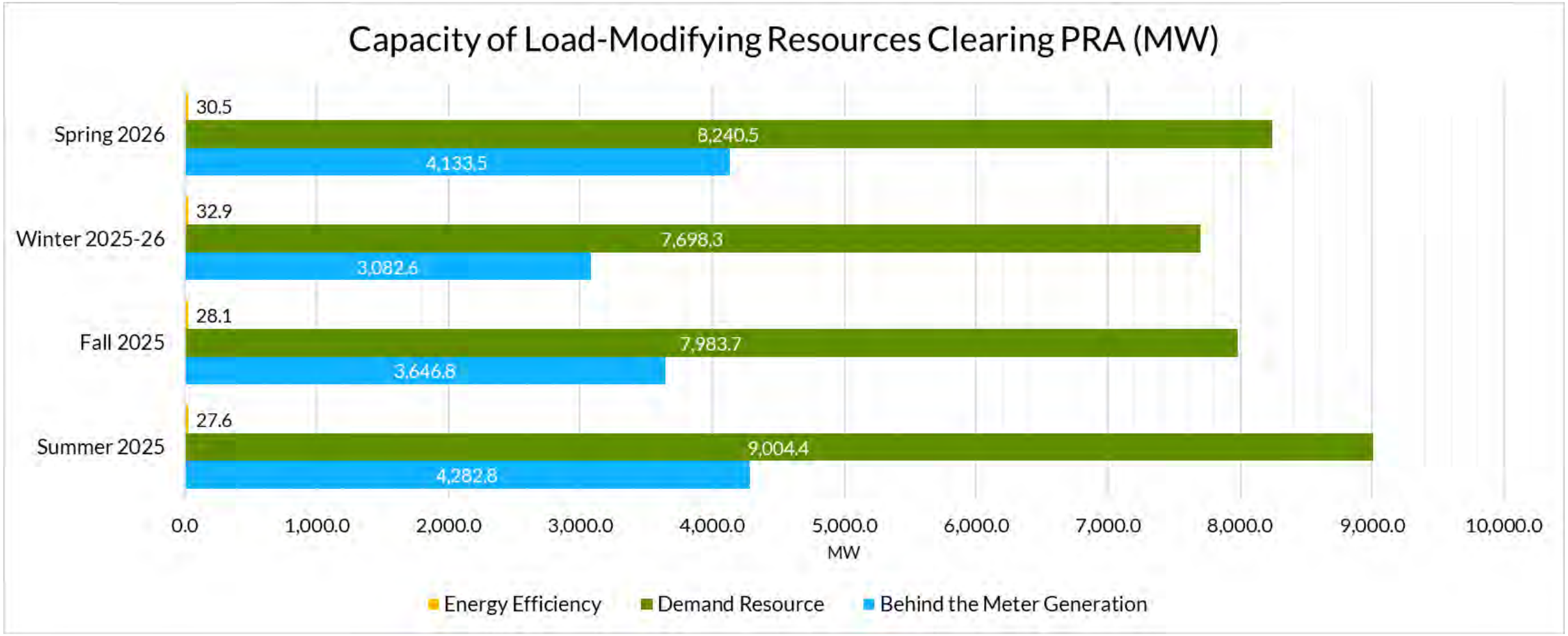
PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025/26 Seasonally Cleared Load Modifying Resources Comparison



Visit MISO's Help Center
for more information
https://help.misoenergy.org/

MISO's Planning Resource Auction indicates sufficient resources

Improved pricing signal more accurately highlights reliability risk

For Immediate Release

April 28, 2025

Media Contact

Brandon Morris

CARMEL, Ind. — Today, MISO released the 2025 Planning Resource Auction (PRA) results indicating adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026). While the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint.

This is the first year MISO utilized a Reliability-Based Demand Curve (RBDC), which introduces a reliability-focused pricing structure that more accurately reflects the increasing value of accredited capacity as the system approaches minimum resource adequacy targets.

"MISO's market reforms continue to assist in providing pricing signals that improve market efficiency and enhance reliability across the footprint," said Aubrey Johnson, MISO's vice president of system planning and competitive transmission. ""We developed the RBDC through extensive collaboration with the Organization of MISO states, our stakeholders and our Independent Market Monitor to ensure this proactive approach helps meet the future needs of our evolving fleet."

The seasonal Auction Clearing Prices are:

- Summer (June, July and August) $666.50/MW-day
- Fall (September, October and November)
  - $91.60/MW-day for the North/Central subregion
  - $74.09/MW-day for the South subregion
- Winter (December, January and February) $33.20/MW-day
- Spring (March, April and May) $69.88/MW-day
- Annualized, the prices are $217/MW-day for the North/Central region and $212 for the South region.

The majority of MISO's Load Serving Entities (LSEs) either self-supply or secure the capacity they need before the auction. Those that enter the auction to procure capacity must pay the Auction Clearing Price and those holding excess capacity sell it at the same clearing price. The impact on consumer costs will vary and depends on factors such as the size of any capacity shortfall and the terms of wholesale power purchase agreements or state-regulated retail rates.

"This year's results underscore MISO's proactive Market Redefinition efforts to enhance resource availability as outlined in the Reliability Imperative." Johnson continues. "MISO, our states and our stakeholders continue to make progress responding to the resource adequacy challenges we face, and these results offer valuable insights to allow members to maximize their existing resources and plan for the ongoing energy transition."

MISO's Independent Market Monitor has reviewed and agreed with the offers and results of the 2025 PRA. MISO will host the 2025 Planning Resource Auction Results meeting April, 29 at 10 a.m. ET.

##

MEDIA CONTACT:
Brandon D. Morris

About MISO

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. 45 million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to reliable, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and innovative solutions for our changing industry. MISO operates one of the world's largest energy markets with more than $40 billion in annual gross market energy transactions.

News Release Link



GET STARTED

Login/Profile

Help Center

Contact Us

Code of Conduct

Compliance

DISCOVER

Calendar

Careers

MISO Matters - Blog

Notifications

Legal and Privacy

POPULAR LINKS

Market Displays

Operation Displays

Market Reports

Markets and Operations

Extranet

Copyright © 2010-2025 Midcontinent Independent System Operator, Inc. All rights reserved.

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking

Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	
BAL-502-RF-03	08/10/17	NERC BOT Approved	
BAL-502-RF-03	10/16/17	FERC Approved	

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

A REPORT TO CONGRESS AND THE STATES PURSUANT TO SECTIONS 1234 AND 1832 OF THE ENERGY POLICY ACT OF 2005

United States Department of Energy

February 2007

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

A REPORT TO CONGRESS AND THE STATES PURSUANT TO SECTIONS 1234 AND 1832 OF THE ENERGY POLICY ACT OF 2005

Sections 1234 and 1832 of the Energy Policy Act of 2005 (EPAct)[1] direct the U.S. Department of Energy (the Department, or DOE) to:

1) Study the procedures currently used by electric utilities to perform economic dispatch;
2) Identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch; and
3) Study the potential benefits to residential, commercial and industrial electricity consumers nationally and in each State if economic dispatch procedures were revised to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

EPAct defines "economic dispatch" to mean "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." [EPAct 2005, Sec. 1234 (b)] On November 7, 2005, the Department submitted a report to Congress in fulfillment of this requirement, *The Value of Economic Dispatch*.[2] The Act also requires the Secretary of Energy to submit a yearly report to Congress and the States "on the results of the study conducted under subsection (a), including recommendations to Congress and the States for any suggested legislative or regulatory changes." [EPAct 2005, Sec. 1234 (c)]

This report responds to the latter requirement, as the first annual study following up on the initial economic dispatch report to Congress and the States. It concludes that while the value of economic dispatch to promote reliability and efficiency of generation resources remains unchanged, national or state policy with respect to economic dispatch has changed very little since November 7, 2005. Accordingly, it does not appear that the practice of economic dispatch has undergone significant change.

---

[1] The two sections have identical language. Hereafter in this report, citations will be to section 1234.

[2] This report, issued by the Department of Energy on November 7, 2005, can be found at http://www.oe.energy.gov/epa_sec1234.htm .

Review of the Department of Energy's 2005 Economic Dispatch Report

Security-constrained economic dispatch is an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system. DOE's 2005 report found that security-constrained economic dispatch benefits electricity consumers by systematically increasing the use of the most efficient generation units (and demand-side resources, where available). This can lead to:

> … better fuel utilization, lower fuel usage, and reduced air emissions than would result from using less efficient generation. As the geographic and electrical scope integrated under unified economic dispatch increases, additional cost savings result from pooled operating reserves, which allow an area to meet loads reliably using less total generation capacity than would be needed otherwise. Economic dispatch requires operators to pay close attention to system conditions and to maintain secure grid operation, thus increasing operational reliability without increasing costs. Economic dispatch methods are also flexible enough to incorporate policy goals such as promoting fuel diversity or respecting demand as well as supply resources. Over the long term, economic dispatch can encourage new investment in generation as well as in transmission expansion and upgrades that enhance both reliability and cost savings.[3]

The initial report found that there have been many studies of the savings from various aspects of economic dispatch, but the studies do not provide consistent estimates of the benefits and effectiveness of economic dispatch. Compiling the results of an extensive survey of the electric industry's use of economic dispatch, the report found that all of the regional grid operators (Regional Transmission Operators and Independent System Operators), and the utilities in the third of the nation outside grid operator footprints use economic dispatch to manage and dispatch their generation units. At the same time, although regional grid operators and utilities observe the basic principles of security-constrained economic dispatch, the details of dispatch execution and the constraints placed around dispatch operations vary widely. The report concluded that there is room to improve economic dispatch practices to reduce the total cost of electricity and increase grid reliability. It did not attempt, however, to estimate the magnitude of such potential improvements.

Review of the FERC-State Economic Dispatch Joint Board Recommendations and Outcomes

Section 1298 of EPAct directed the Federal Energy Regulatory Commission (FERC) to convene regional joint boards with state regulators to:

> … consider issues relevant to what constitutes "security constrained economic dispatch" and how such a mode of operating an electric energy system affects or

[3] *Ibid.* at 3-4.

> enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to the Commission regarding such issues.[4]

On September 30, 2005, FERC issued an order convening joint boards in each of four designated regions (Northeast, PJM-MISO, South and West). The boards met over a period of several months and submitted regional reports to FERC, which compiled those reports with additional commentary in a submittal to Congress on July 31, 2006.[5]

The analysis and conclusions about economic dispatch varied significantly across the four regions. However, no joint board recommended any material changes to the way that economic dispatch is conducted within its region. FERC's report summarizes:

> … Regions where centralized dispatch predominates (PJM-MISO, Northeast) did not propose changing the basic dispatch or pricing mechanisms, and regions where individual utility dispatch predominates (South, West) did not propose new initiatives for greater centralization of the dispatch. In regions with existing RTOs, there were a number of recommendations for specific improvements within the existing centralized dispatch framework, but no new proposals for fundamental changes in the way the RTOs operate the dispatch. In regions where individual utility dispatch predominates, the boards were open to voluntary changes to aspects of the existing dispatch, or continued industry pursuit of regional dispatch on a voluntary basis, as long as these initiatives could be demonstrated to provide benefits to customers and gain appropriate state and federal approvals. However, these boards did not call for any specific initiatives and opposed any form of mandated modification.[6]

Since the FERC joint board report contains an excellent summary of the joint boards' concerns and conclusions, the present report addresses only the specific, affirmative recommendations offered by the various joint boards:

- The Northeast Joint Board recommended broadening the application of economic dispatch through greater coordination between the NYISO and ISO-NE, consideration of possible coordination with other areas, meetings with stakeholders on such coordination, examination of the possibility of coordination with other areas, and preparation of a report by NYISO and ISO-NE to FERC describing their seams elimination plans. That report had not been filed when this report was written.

---

[4] EPAct, Section 1298.

[5] Federal Energy Regulatory Commission, "Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations – A Report to Congress Regarding the Recommendations of Regional Joint Boards For the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005," July 31, 2006, at http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf .

[6] *Ibid.* at 10.

- The PJM-MISO Joint Board recommended examining the cost and feasibility of consolidating MISO and PJM economic dispatch and expanding further to include areas not currently under RTO-managed dispatch, subject to cost-effectiveness and applicable state laws. They also recommended continued improvements to the seams coordination between the two RTOs. This work is ongoing.
- The Western Joint Board recommended the conduct of studies to determine the potential of better dispatch coordination across larger sections of the region, particularly to improve the dispatch of renewables and to coordinate import and export scheduling.
- The Northeast Joint Board recommended that the RTOs improve data transparency by making bid data available more quickly to market participants.
- The PJM-MISO Joint Board asserted the need for continued RTO independence and objectivity in the conduct of economic dispatch.
- The PJM-MISO Joint Board recommended continued attention by the RTOs and state regulators to enable greater demand response participation in economic dispatch. PJM now allows demand response resources to bid into its real-time energy markets.
- Similarly, the Western Joint Board recommended broadening the definition of security-constrained economic dispatch to include policies such as demand response that affect dispatch beyond purely economic and security considerations.
- The PJM-MISO Joint Board recommended that the RTOs establish a clear benchmark to assess the effectiveness of economic dispatch at achieving reliability and cost-effectiveness objectives.
- The Western Joint Board recommended against conducting a more detailed study of utility economic dispatch methods (as suggested in the Department's 2005 report), on the grounds that such a review was not likely to add value.
- The Southern and Western Joint Boards considered the DOE recommendation concerning the standardization of non-utility generator-to-buyer contract terms, and concluded that this was worth pursuing on the condition that the results maintain flexibility and be applied regionally rather than nationally. However, no organization or agency has pursued this recommendation.
- The Northeast Joint Board recommended that FERC request the ISO-RTO Council to identify best practices for future improvements in economic dispatch tools. However, to date FERC has not issued a request of this nature.

Other Activities and Issues Related to Economic Dispatch

FERC Reform of Open Access Transmission Tariff

The Commission recently issued Order 890, in which it revised its *pro forma* Open Access Transmission Tariff, under which transmission operators offer transmission service for all bulk power sellers and buyers.[7] A common theme within FERC's reform effort, supported by many

[7] FERC Order No. 890, "Preventing Undue Discrimination and Preference in Transmission Service," February 16, 2007, RM05-17-000 and RM05-25-000.

comments in response to FERC's Notice of Inquiry on OATT reform,[8] was that greater transparency in grid conditions, operations, and planning would enable many transmission customers – producers and purchasers – to participate more effectively in the wholesale electric market.

While many of the subjects covered by Order 890 do not address economic dispatch directly, the order will affect the ways that generation resources (including independent power producers) are treated under economic dispatch, whether conducted by a vertically integrated utility or an independent grid operator. The principal changes required by the order include:

- A requirement that public utilities work through the North American Electric Reliability Corporation (NERC) to develop consistent methodologies for calculating Available Transfer Capability (ATC) and to publish those methodologies. Calculating and publishing ATC is one of the "most critical functions under the *pro forma* OATT because it determines whether transmission customers can access alternative power supplies," the Commission said.[9]
- Each transmission provider's planning process must meet nine specified planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.
- The rule reforms the pricing of energy and generator imbalances to require charges to be related to the cost of correcting the imbalance, to encourage efficient scheduling behavior and to exempt intermittent generators, such as wind power producers, from higher imbalance charges in recognition of the special circumstances presented by such resources.
- The Commission adopted a conditional firm component to long-term point-to-point transmission service addressing situations in which firm service can be provided for most, but not all, hours of the requested time period. The rule also reforms the existing requirements for redispatch service to ensure that the requirements are of greater use to transmission customers and more consistent with reliable planning and operation of an area's system.

Load forecasting

As noted in the Department's November 2005 Economic Dispatch Report, improving the quality and accuracy of load forecasting would improve the reliability and cost-minimization outcomes of economic dispatch. This is because most of the units available to meet load in real time were identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. While the cost of over-estimating load (in which case the load prediction is notably lower than actual) is relatively low and primarily financial (because money and fuel was expended to make a generator available although it was not fully

[8] Federal Energy Regulatory Commission, "Preventing Undue Discrimination and Preference in Transmission Services," Notice of Inquiry, September 16, 2005, and comments, found at http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp .
[9] Federal Energy Regulatory Commission, news release regarding Order 890, February 15, 2007.

utilized), significantly under-estimating load can compromise reliability and cause sharp short-term increases in real-time wholesale market prices.

The importance of accurate load forecasting was demonstrated recently by the heat wave that occurred across most of the nation in July, 2006, the second hottest July on record in the United States. Due to the combination of the heat wave and a strong economy, total energy production in July 2006 was 4.3 percent higher than that in July 2005.[10] The California ISO, for example, reported that energy demand experienced within its control area on July 21 and 22 broke all previous records, demonstrating "tremendous growth in the demand for electricity – the amount of growth [not] forecasted to appear [until] five years from now."[11] Further, demand in California continued to rise on following days and was prevented from exceeding the area's production capacity only through the combination of aggressive customer conservation efforts and the loss of hundreds of distribution transformers which failed in the heat, removing significant additional load from the grid. A similar but less protracted disruption in electric service occurred in Texas on April 17-18, 2006.[12] Although long-term load forecasting is subject to many uncertainties, improvements in near-term load forecasting could lead to greater cost savings as well as improved reliability.

Private Sector Initiatives

The largest geographic and electric systems integrated under security-constrained economic dispatch are operated by RTOs and ISOs. Those grid operators have made specific changes to their economic dispatch efforts, including coordination of market operations, congestion management and redispatch between PJM and MISO, and co-optimization of resource prices across multiple markets by ISO-New England.

Commercial software vendors continue to work to improve the quality and scope of the tools used for security-constrained unit commitment and security-constrained economic dispatch. Because RTOs manage significantly greater resource fleets than traditional utilities – for instance, PJM handles over 150 gigawatts of resources spanning 30,000 "buses,"[13] while traditional utilities might dispatch across 5,000 buses – the scope of dispatch calculations has raised new computational challenges. At the same time, software developers are developing new algorithms to solve large-scale security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) problems, using new techniques such as temporal coupling and mixed integer programming to improve modeling of specific resource types and

[10] Energy Information Administration," Monthly Flash Estimates of Electric Power Data", September 19, 2006, Data for July 2006.
[11] California ISO, "Conservation Works! More Conservation Needed as Peak Demand Skyrockets to Critical Peak Monday," July 23, 2006.
[12] See http://www.nbc5i.com/news/8794207/detail.html?rss=dfw&psp=news and other local news sources.
[13] The term "bus" is used in the electricity industry to refer to a node in an electrical transmission network where one or more elements are connected together.

optimize multiple complex power flows simultaneously.[14] Demands from the software vendors' most challenging customers -- large grid operators such as the NYISO, ISO-NE and PJM -- are driving and supporting such vendor initiatives.

Conclusions

Other than some responses to the FERC-State Joint Board studies, few significant changes were made in 2006 in the policies and practices for economic dispatch in the United States electric grid. More significant changes are likely to result, however, from the industry's implementation of FERC's Order 890. Although the order was issued in mid-February 2007, the rulemaking process was initiated in September 2005, and full implementation of the order will take many months.

[14] E-mail from Avnaesh Jayantilal, Director Market Management Systems, Areva T&D, Redmond WA, October 13, 2006.

175 FERC ¶ 61,224
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Richard Glick, Chairman;
James P. Danly, Allison Clements,
and Mark C. Christie.

Joint Federal-State Task Force on Electric Transmission Docket No. AD21-15-000

ORDER ESTABLISHING TASK FORCE AND SOLICITING NOMINATIONS

(Issued June 17, 2021)

1. Section 209(b) of the Federal Power Act (FPA) authorizes the Federal Energy Regulatory Commission (the Commission or FERC) to confer with state commissions "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction" of such state commissions and FERC, including through joint hearings.[1] Pursuant to that authority, in this order, we establish a Joint Federal-State Task Force on Electric Transmission (Task Force); solicit nominations for state commission representation on the Task Force; set forth preliminary details of the Task Force; and identify topics for the Task Force to consider.

I. Task Force

2. Pursuant to section 209(b) of the FPA, we hereby establish the Task Force to conduct joint hearings on the transmission-related topics outlined below. Developing new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities. Federal and state regulators each have authority over transmission-related issues, meaning that transmission developers must successfully navigate different federal and state regulatory processes. In addition, the development of new transmission infrastructure often affects numerous different priorities of federal and state regulators (e.g., reliability, customer protection, environmental considerations). As a result, the area is ripe for greater federal-state coordination and cooperation. We

[1] 16 U.S.C. § 824h(b).

believe that a formal structure to jointly explore transmission-related issues is important in order to secure the benefits that transmission can provide and is in the public interest.[2]

3. The Task Force will be comprised of all FERC Commissioners as well as representatives from 10 state commissions. State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. State commission representatives will sit in an advisory capacity. We request that the National Association of Regulatory Utility Commissioners (NARUC) submit nominations to the Commission, in this docket, for the 10 state commission representatives no later than 30 days from the date of this order. We further request that two state commission representatives originate from each NARUC region,[3] recognizing that transmission-related issues may be viewed differently not only within, but also among different parts of the country. Although we solicit 10 nominations for state commission representatives on the Task Force, all state commissions will be invited to suggest agenda topics for public meetings of the Task Force and to submit comments before and after on the topics being discussed at such meetings. In addition, in the future, the Task Force may convene regional meetings with opportunity for participation by all state commissions in the region. Staff from FERC, NARUC, and the state commissions of state commission representatives will be appointed to support the work of the Task Force.

4. The Task Force will convene for multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, after consulting with all Task Force members and considering suggestions from state commissions. Meetings will be open to the public for listening and observing and on the record. We expect the initial public meeting of the Task Force to be held during the Fall 2021. The Task Force will expire three years after the first public meeting but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

5. The Task Force has the authority to examine the issues identified below, including soliciting oral and written input from interested parties. The Task Force may make

---

[2] *See* 18 C.F.R. § 385.1301(b) (2020) (suggesting FERC or any state commission "will freely suggest cooperation with respect to any proceeding or matter affecting any public utility . . . subject to the jurisdiction of the Commission and of a State commission, and concerning which it is believed that cooperation will be in the public interest"); *see also id.* § 385.1305(c) (stating that FERC or any state commission "should feel free to suggest or request a joint . . . hearing at any time").

[3] *See* Nat'l Ass'n of Regul. Util. Comm'rs, https://www.naruc.org/meetings-and-events/regionals/ (last visited June 2, 2021) (identifying five regional associations).

recommendations to FERC on potential modifications to FERC's regulations, present recommendations at a monthly FERC open meeting, and develop a record to be incorporated into FERC and/or state commission proceedings.

II. Issue Statement

6. The Task Force will focus on topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective. Topics that the Task Force may consider include the following:

- Identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers;

- Exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals;

- Exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions;

- Reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms;

- Examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and

- Discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

III. Next Steps

7. After receiving nominations from NARUC, due within 30 days of the date of this order, for the 10 state commission representatives, we will issue a subsequent order, listing members of the Task Force and their roles and fixing the time and place for the first public meeting. At least two weeks prior to the first public meeting, we will issue an order with an agenda, developed in collaboration with Task Force members and in consideration of suggestions from state commissions.

By the Commission. Commissioner Chatterjee is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

NEWS RELEASES

FERC, NARUC Establish Federal-State Current Issues Collaborative

March 21, 2024
Items E-5
Docket Nos. AD21-15, AD24-7

FERC voted today to establish a new Federal-State Current Issues Collaborative to build on nearly three years of successful transmission-related task force discussions with state utility regulators and expand their efforts to energy sector issues where there are relevant jurisdictional connections or potential regulatory gaps.

The new Collaborative, formed in conjunction with the National Association of Regulatory Utility Commissioners (NARUC), expands on the last three years of work of the Joint Federal-State Task Force on Transmission. The Collaborative will provide a venue for federal and state regulators to share perspectives, improve understanding and, where appropriate, identify potential solutions regarding challenges and coordination on matters that affect specific state and federal regulatory jurisdictions. Potential topics include exploring where best to coordinate between state and federal regulators on issues ranging from electric reliability and resource adequacy to natural gas-electric coordination, wholesale and retail markets, new technologies and innovations, and infrastructure.

> "The past three years of our Task Force work have proven just how important it is for FERC and state regulators to meet and expand our shared perspectives on important electricity sector matters that we all grapple with on a daily basis," FERC Chairman Willie Phillips said. "I look forward to this expanded collaboration with our state colleagues."

"The role of state utility commissioners is increasingly more challenging and consequential to the quality of life, safety and economic health of this nation. Ensuring the reliability of the grid as the energy sector evolves at a rapid pace is crucial," said NARUC President Julie Fedorchak. "We appreciate the opportunity to continue these dialogues with FERC on matters at the cross-section of state and federal jurisdictions, which ultimately affect the well-being of our society."

"Transmission planning, siting and cost allocation are growing issues in some portions of our nation that are presenting challenges for state and federal regulators alike," said North Carolina Commissioner Kim Duffley, who represented the states as the co-chair of the task

force. “I greatly appreciate the opportunity to have served with my fellow regulators on the task force, as the process allowed for meaningful dialogue and assisted in providing a clearer understanding of regional differences. The states look forward to seeing the beneficial results of our conversations and working with our federal partners on other significant federal-state issues.”

The Joint Federal-State Task Force on Electric Transmission, established in 2021, had its final meeting in February 2024. Since its first meeting in November 2021, the Task Force addressed numerous transmission-related topics, including regional transmission planning and cost allocation, generator interconnection, interregional transmission, oversight of transmission costs, physical security, grid enhancing technologies and siting.

The Federal-State Issues Collaborative will convene its first meeting this fall; it will expire in the fall of 2027. The Collaborative structure will be similar to that of the Task Force: It will be comprised of all sitting FERC Commissioners and representatives from 10 state commissions to be nominated by NARUC, with two state nominees from each NARUC region. State members will serve one-year terms.

R24-12

Contact Information

News Media
Email: MediaDL@ferc.gov

This page was last updated on March 21, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company	)	
	)	**Docket No. EL25-90-000**
v.	)	
	)	
Midcontinent Independent System Operator, Inc.	)	

ANSWER OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

The Midcontinent Independent System Operator, Inc. ("MISO" or "Respondent") submits[1] this Answer to the Complaint of Consumers Energy Company ("Consumers Energy" or "Complainant"). Consumers Energy filed the Complaint in response to an order issued by the U.S. Secretary of Energy pursuant to Federal Power Act ("FPA") section 202(c) and section 201(b) of the Department of Energy Authorization Act.[2] The DOE Order determined "that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes[.]"[3] To address that emergency, the DOE Order directs MISO and Consumers Energy to take all measures necessary to ensure that the J.H. Campbell coal-fired power plant in West Olive, MI ("Campbell Plant") is available to operate.[4] Consumers Energy's Complaint requests that MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") be revised to permit

1 *See* Rules 206 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.206(f) (2025); 18 C.F.R. § 385.213 (2025).
2 U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) ("DOE Order").
3 DOE Order at 1.
4 DOE Order at 2.

recovery of costs incurred incident to the DOE Order, and provides draft Tariff language for the Commission's review.

As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region.[5] While MISO does not intend to contest, within the context of this docket, the characterization within the Order that an emergency exists "due to a shortage of electric energy . . . [or] a shortage of facilities," it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order. The clearing of sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year reflects the diligent efforts of MISO's members, Market Participants, Relevant Electric Retail Regulatory Authorities (RERRA) and the Federal Energy Regulatory Commission (FERC) to establish policies and processes that address both immediate, and future capacity requirements. MISO continues to work with these parties in the context of anticipated growing demand for electricity, planned electric generating facility retirements, and an evolving mix of new electric generating resources to refine processes that address the challenges ahead. MISO is confident that these collaborative efforts do not require further intervention and will help ensure the region continues to procure sufficient capacity to meet demand.

MISO acknowledges that the DOE Order directs Consumers Energy "to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."[6] MISO also acknowledges that the DOE Order provides that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[7] MISO supports the addition of a cost recovery schedule to the

5 Department of Energy Order No. 202-25-3 (May 23, 2025) at p. 2.
6 DOE Order at 3.
7 DOE Order at 3.

Tariff, subject to the reservations noted below, and believes that a Commission finding that such a mechanism be incorporated in the Tariff would further compliance with the DOE Order by both Consumers and MISO.

I. BACKGROUND

The Secretary of Energy issued the DOE Order on May 23, 2025.[8] The DOE Order identifies an "emergency situation" in the MISO region and states that MISO "faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output."[9] The DOE Order notes that the Campbell Plant is scheduled to cease operations on May 31, 2025," and concludes that the Campbell Plant's retirement "would further decrease available dispatchable generation within MISO's service territory[.]"[10] The DOE Order states that, although MISO and Consumers Energy incorporated the Campbell Plant's planned retirement into their supply forecasts and acquired a 1,200 MW natural gas plant in Covert, MI, the North American Electric Reliability Corporation's ("NERC") analysis still anticipates an "elevated risk of operating reserve shortfalls."[11] The DOE Order concludes that "additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[12]

The DOE Order directs MISO and Consumers Energy to "take all measures necessary to ensure that the Campbell Plant is available to operate."[13] MISO is "directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers" and "to provide the [DOE] with information concerning the measures it has taken and is planning to take to ensure

8 DOE Order at 3.
9 DOE Order at 1.
10 DOE Order at 1.
11 DOE Order at 2.
12 DOE Order at 3.
13 DOE Order at 2.

the operational availability and economic dispatch of the Campbell Plant consistent with the public interest."[14] MISO notes that it is working closely with Consumers and the other owners of the Campbell Plant to ensure the plant is available to operate in compliance with the DOE Order.

The DOE Order states that, to "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so."[15] The Order further provides that "Consumers [Energy] is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."[16] The DOE Order states that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[17]

II. ANSWER

A. The Tariff Does Not Currently Include a Mechanism to Allow Cost Recovery Pursuant to the DOE Order.

Consumers Energy observes that there is no MISO Tariff provision that would permit Consumers Energy's costs of complying with the DOE Order to be allocated to Load Serving Entities ("LSEs") in MISO's northern and central zones, and that MISO does not have the unilateral authority to offer Consumers Energy a section 202(c) rate agreement.[18] MISO agrees. MISO acknowledges that its Tariff does not currently include a mechanism to allow the cost recovery contemplated by the DOE Order. As discussed below, MISO does not oppose the addition of a cost recovery schedule to its Tariff that would allow Consumers Energy to recover its costs as contemplated by the DOE Order.

---

14 DOE Order at 2-3.
15 DOE Order at 3.
16 DOE Order at 3.
17 DOE Order at 3.
18 Complaint at 18.

B. MISO Does Not Oppose the Addition of a Cost Recovery Schedule for the Recovery of These Costs, and Will File a Cost Recovery Schedule to the Extent Directed by the Commission.

MISO does not oppose the addition of a cost recovery schedule that would permit Consumers Energy to recover the costs incurred as a result of its efforts to comply the DOE Order. MISO will file such a schedule if directed by the Commission.

C. MISO Reserves Its Right to Modify or Otherwise Change the Cost Recovery Allocation Formula, As Necessary, to Account for Existing Tariff Requirements or Changes.

MISO reserves the right to modify, adjust, or otherwise change the cost recovery allocation formula proposed by Consumers, should it be necessary, to account for existing Tariff requirements and to include other clarifications as may be appropriate.

III. ADMISSIONS AND DENIALS; AFFIRMATIVE DEFENSES

MISO denies all allegations in the Complaint not specifically and expressly admitted herein.[19]

IV. COMMUNICATIONS

All notices and communications with respect to this proceeding should be directed to:

Timothy Caister*
Vice President, Legal & Federal Regulatory Affairs
Michael Kessler
Managing Assistant General Counsel
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5400
tcaister@misoenergy.org
mkessler@misoenergy.org

James C. Holsclaw*
Taylor M. Carpenter
Calfee, Halter & Griswold, LLP
3900 Salesforce Tower
111 Monument Circle
Indianapolis, IN 46204
317-308-4266
jholsclaw@calfee.com
tcarpenter@calfee.com

*Persons designated to receive official service

[19] 18 C.F.R. § 385.213(c)(2)(i)-(ii).

V. CONCLUSION

WHEREFORE, MISO respectfully requests that the Commission accept this answer.

Respectfully submitted,

/s/ Timothy Caister
Timothy Caister
Vice President, Legal & Federal
Regulatory Affairs
Michael Kessler
Managing Assistant General Counsel
Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5400
tcaister@misoenergy.org
mkessler@misoenergy.org

James C. Holsclaw
Taylor M. Carpenter
Calfee, Halter & Griswold, LLP
3900 Salesforce Tower
111 Monument Circle
Indianapolis, IN 46204
Telephone: (317) 308-4266
jholsclaw@calfee.com
tcarpenter@calfee.com

Counsel for Midcontinent Independent System Operator, Inc.

CERTIFICATE OF SERVICE

I hereby certify that I have on this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 19th day of June, 2025 in Carmel, Indiana.

/s/ Adriana Rodriguez
Adriana Rodriguez
Midcontinent Independent
System Operator, Inc.

Dated: June 19, 2025

MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot

By Amanda Durish Cook

MINNEAPOLIS — MISO Independent Market Monitor David Patton called NERC's Long-Term Reliability Assessment inaccurate for labeling MISO a high-risk area and said he believes MISO is in a good reliability position.

"We find that it is completely inaccurate. MISO should not be colored in red," Patton said at a June 10 Markets Committee meeting of the MISO Board of Directors.

Patton faulted NERC for apparently conflating installed capacity with unforced capacity in the assessment's totals. He said NERC tallied unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. He said the blunder lowered the footprint's capacity sums on paper by more than 10 GW.

"I don't frankly understand how they did this," Patton said. "They basically presented an apples and oranges assessment."

NERC's Long-Term Reliability Assessment predicted MISO could be confronted with capacity shortfalls in 2025. It assumed the RTO would have 132.2 GW in generating capacity, or 124.4 GW after factoring in all retirement announcements. (See *NERC Warns Challenges 'Mounting' in Coming Decade*.)

Ahead of summer, MISO reported it has 143.1 GW in offered capacity available to it to meet a likely 123-GW annual peak. (See *MISO Prepping for Likely 123-GW Summer 2025 Peak*.) Altogether, the RTO has 203 GW of installed capacity.

Patton said NERC's lapse is influencing national policy, evidenced by the Department of Energy's directive to keep Consumers Energy's 1.4-GW J.H. Campbell coal plant in Michigan operating over the summer. (See *Consumers Energy Seeking Compensation for Keeping Campbell Open*.) He said NERC's projection could bleed into other rule changes.

"That sort of initiative can lead to FERC ordering market changes that are unnecessary," Patton said.

Patton also said MISO overstated load predictions used in NERC's assessment by submitting non-coincident peak forecasts instead of coincident peaks, raising its load requirements and lowering the calculated capacity margin.

Patton said of the four RTO markets he monitors, "I would say MISO is most reliable of the four."

"It seems like a combination of errors that seems correctable here, but there isn't a path for correction," MISO Director Barbara Krumsiek said.

Patton said he hopes NERC will rectify its methods that inform the long-term assessment by the next December report. He said he has reached out to NERC and committed to working with the regulatory authority on its approach.

Michelle Bloodworth, CEO of coal lobby organization America's Power, questioned whether it was appropriate for the MISO Market Monitor to question a "credible institution" such as NERC. She said she believed MISO's "elevated risk" status under the assessment was apt.

Bloodworth praised the DOE's actions to keep J.H. Campbell available for a little while longer. She noted that Cleco's 568-MW Big Cajun II Unit 1 shuttered March 31 due to a settlement decree; she said having the coal plant online at the time might have helped matters during MISO's load shedding orders in the New Orleans area on May 25. (See *NOLA City Council Puts Entergy, MISO in Hot Seat over Outages*.)

At the same meeting, MISO said it likely will manage higher-than-normal temperatures paired with drought over the summer.

"If you're dry and have a pervasive heatwave going on, it can compound challenges in the operating room," MISO Executive Director of Market Operations JT Smith said.

Smith said a doubled-in-size solar fleet also likely will test MISO's ramp and regulation capabilities in its ancillary market. He said MISO operators could be managing unavailable resources and higher-than-expected load throughout summer.

Why This Matters

MISO IMM David Patton panned the RTO's precarious standing in NERC's Long-Term Reliability Assessment. He waved away resource adequacy concerns and said NERC botched a margin-to-capacity requirement comparison, apparently mixing up unforced capacity and installed capacity.

As part of a five-year update, Vice President of Operations Renuka Chatterjee said MISO finds itself in the most "dynamic and demanding" operating environment it ever has. She cited steeper evening ramps and mounting long-duration outages, forecasting challenges and stability risks.

MISO entered summer June 1 with a $666.50/MW-day capacity price, signifying the premium the RTO has put on new capacity. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

Carrie Milton, of the IMM staff, said if generation operators had held off on powering down about 1.6 GW until September, it would have lowered capacity prices to $472/MW-day in the summer.

But Milton said the Campbell plant is not factored into MISO's clearing prices and isn't necessary for reliability during the season. She said MISO's auction already returned a better than one-day-in-10-years standard without the large coal plant.

"We are more than adequate," Patton said. He repeated that he has "no material concerns" over MISO's resource adequacy for the upcoming summer.

Patton said factoring in imports and typical planned and forced outages, MISO has a comfortable, 12.2% reserve margin. ■

© 2025 RTO Insider | www.rtoinsider.com

Congressional Research Service
Informing the legislative debate since 1914

Federal Power Act: The Department of Energy's Emergency Authority

June 12, 2025

Congressional Research Service
https://crsreports.congress.gov
R48568

CRS REPORT
Prepared for Members and
Committees of Congress

Contents

History of Section 202(c) 1
DOE Implementation 1
Trump Administration Actions 3
Issues for Congress 4

Contacts

Author Information 5

Section 202(c) of the Federal Power Act (16 U.S.C. §824a(c)) grants the Secretary of Energy certain authorities over the temporary operation of the electricity system during emergencies. Actions by the Trump Administration have highlighted this authority and raised questions about its future implementation. This report provides a brief history of the emergency authorities and discusses current issues.

History of Section 202(c)

The Federal Power Act was enacted in 1935 and included emergency authority language. At the time, federal oversight of the electricity system was conducted by the Federal Power Commission (FPC). Now, the Federal Energy Regulatory Commission (FERC) has most responsibilities for electricity system oversight—but not for emergencies. The emergency authority was transferred to the Secretary of Energy when the Department of Energy (DOE) was established by the Department of Energy Organization Act (P.L. 95-91) in 1977. Hereinafter, the emergency authority is described as residing with DOE.

Section 202(c) provides DOE broad discretion to require almost any change to the operation of the U.S. electricity system on a temporary basis. Specifically, DOE may "require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."

DOE may execute this authority during war or at any other time it "determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." This report focuses on the authority as used during emergencies, not war, and it focuses on DOE's authority—it does not discuss other energy emergency authorities.[1]

In 2015, Congress amended Section 202(c) to specify how the emergency authority should interact with environmental requirements for power plants. In practice, the amendments prioritize electric reliability over environmental outcomes, essentially by providing a waiver of federal, state, or local environmental laws and regulations during times of emergencies.

This waiver has limitations. First, DOE emergency orders that may result in conflicts with environmental requirements may be issued only for 90-day periods. They may be renewed for additional 90-day periods as long as DOE deems these renewals necessary to meet the emergency.

Second, if an emergency order would result in a violation of a federal, state, or local environmental law or regulation, DOE must ensure the order is in effect "only during hours necessary to meet the emergency and serve the public interest." Lastly, DOE must "to the maximum extent practicable" ensure the order is consistent with environmental laws or regulations and "minimizes any adverse environmental impacts."

DOE Implementation

DOE's regulations for implementing its emergency authority were finalized in 1981.[2] The regulations define terms, including "emergency," and specify requirements for requesting an emergency order.

[1] For example, in the 1970s, Congress passed several laws granting the President certain authorities to respond to energy shortages at the time. A discussion of those laws is beyond the scope of this report.

[2] 10 C.F.R. §§205.370-205.379.

The Section 202(c) emergency authority is focused primarily on short-term situations—though, as shown below, DOE has exercised this authority in situations of varying duration. DOE's regulations emphasize the short-term nature of "emergencies" in this context. In the 1981 rulemaking, DOE explained,

> The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the 'Definition of Emergency' to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[3]

DOE and FPC have used the emergency authority several dozen times since 1935 in response to different kinds of emergencies.

DOE's website contains information on use of the emergency authority from 2000.[4] From 2000 through May 2025, DOE used its emergency authority in response to 19 events. Eleven events were weather-related and included hurricanes, heat waves, and winter storms. Some events prompted multiple emergency orders, either because more than one utility experienced emergency conditions (e.g., Winter Storm Elliot in 2022) or because the initial emergency order was extended (e.g., the California energy crisis of 2000-2001).

Details on the use of the Section 202(c) emergency authority prior to 2000 are not available in a single DOE repository; they are therefore more difficult to comprehensively compile. According to one compilation, the emergency authority was used 29 times prior to 2000; 22 of these occasions were in association with World War II.[5]

The duration of emergency orders under Section 202(c) has varied; some have lasted just a few hours, while others have been extended to cover events lasting more than a year. Among the orders listed on DOE's website, the shortest order CRS identified occurred in response to a heat wave in Texas in September 2023. DOE granted an emergency order in this case for four hours on each of two days to respond to the highest levels of expected electricity demand.[6] The order allowed one coal-fired unit and 16 natural gas-fired units to operate in violation of limits on sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and wastewater during those hours, if required to maintain reliability.

In the longest event CRS identified, DOE granted multiple renewals to a request to allow two coal-fired units in Virginia to continue operating, as needed for reliability, in violation of mercury emissions limitations while a transmission facility was constructed. Emergency orders in response to that event were in effect from June 16, 2017, to March 8, 2019.[7]

---

[3] Department of Energy (DOE), Economic Regulatory Administration, "Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power" (final rule), 46 *Federal Register* 39985, August 6, 1981, https://archives.federalregister.gov/issue_slice/1981/8/6/39984-39991.pdf#page=2.

[4] See DOE, "DOE's Use of Federal Power Act Emergency Authority," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority; and DOE, "DOE's Use of Federal Power Act Emergency Authority – Archived," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived.

[5] Benjamin Rolsma, "The New Reliability Override," *Connecticut Law Review*, vol. 57, no. 3 (May 2025).

[6] Additional information is available at DOE, "Federal Power Act Section 202(c): ERCOT September 2023," https://www.energy.gov/ceser/federal-power-act-section-202c-ercot-september-2023.

[7] Additional information is available at DOE, "Federal Power Act Section 202(c) – PJM Interconnection & Dominion Energy Virginia, 2017," June 19, 2017, https://www.energy.gov/oe/articles/federal-power-act-section-202c-pjm-interconnection-dominion-energy-virginia-2017.

Trump Administration Actions

On April 8, 2025, President Trump issued Executive Order (E.O.) 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[8] E.O. 14262 directs DOE to "streamline, systemize, and expedite" its processes for issuing emergency orders when "the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure." A blackout is an example of a temporary interruption of electricity supply.

The E.O. additionally directs DOE to develop a protocol to identify generation resources that are critical to system reliability. The protocol must "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." Further, the protocol must prevent, "as the Secretary of Energy deems appropriate and consistent with applicable law," identified resources from "leaving the bulk-power system" or converting fuels in such a way that reduces their accredited capacity. An example of fuel conversion that could reduce accredited capacity is replacing a coal-fired power plant with a solar farm.

The language of the E.O. is nonspecific regarding the duration of any DOE action to retain resources or prevent them from leaving the bulk-power system. The E.O. language could be interpreted to mean DOE should take long-term action (i.e., lasting multiple years) or indefinite action. Emergency orders issued in response to multiyear events would be unusual, though not unprecedented, applications of DOE's Section 202(c) authority. It is unclear the extent to which limits to the authority might exist through judicial review or other avenues if DOE chose to issue long-term or indefinite emergency orders.

DOE issued emergency orders for three separate events in May 2025, all involving seemingly new interpretations of the emergency authority. One event is anticipated electricity supply shortages in Puerto Rico in summer 2025.[9] One of the DOE emergency orders pertaining to Puerto Rico directs the local utility to conduct vegetation management (e.g., shrub clearing) around specified transmission lines on the island.[10] No other emergency order issued from 2000 to the present has addressed vegetation management.

The other events involve elevated risk of supply shortages in parts of the Midwest and Eastern United States this summer. DOE ordered a delay in retirement plans for a coal-fired power plant in Michigan and a natural gas/oil dual-fired power plant in Pennsylvania.[11] Unlike in the cases of other emergency orders issued since 2000, the grid operators in these cases had not requested the delayed retirements. Moreover, neither had identified reliability risks specifically associated with

[8] Executive Order 14262 of April 8, 2025, "Strengthening the Reliability and Security of the United States Electric Grid," 90 *Federal Register* 15521-15522, April 14, 2025, https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[9] For background on Puerto Rico's electricity system, see CRS In Focus IF12913, *Electric Reliability and Resiliency in Puerto Rico*, by Corrie E. Clark.

[10] Secretary of Energy Chris Wright, *Order No. 202-25-2*, May 16, 2025, https://www.energy.gov/sites/default/files/2025-05/PREPA%20202%28c%29%20Emergency%20Measures%20Transmission.pdf.

[11] Secretary of Energy Chris Wright, *Order No. 202-25-3*, May 23, 2025, https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf; and Secretary of Energy Chris Wright, *Order No. 202-25-4*, May 30, 2025, https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf.

the retirement of the power plants in question at the time they approved those retirements. One of the affected grid operators, PJM, issued a supportive statement following the emergency order.[12]

Issues for Congress

E.O. 14262 does not specify how DOE should streamline its processes for issuing emergency orders. Congress could evaluate whether DOE's existing regulations require streamlining and, if Congress determines they do, could provide policy direction and set a timeline for updating the regulations. Congress could also leave it to DOE's discretion as to when and how to update its regulations.

Congress could weigh DOE action in this space against other priorities for the department, given that updating processes for issuing emergency orders could divert DOE resources from other activities. On the one hand, brownouts or blackouts due to insufficient electricity supplies are relatively rare in the United States. Grid operators have their own processes in place for managing the grid during times of supply shortages and, historically, DOE emergency orders have rarely been requested. On the other hand, many observers anticipate electricity demand to increase in the coming years faster than new supply can be brought online. If these trends continue, brownouts or blackouts could become more common, potentially increasing DOE's use of its emergency authority or Congress's interest in addressing emergency situations for electricity supply.

Regarding the statutory authority itself, Congress could consider whether amendments to Section 202(c) of the Federal Power Act are appropriate. The language has remained unchanged since 1935, potentially reflecting Congress's continued view over this time period that the original authorization is appropriate. Nonetheless, the U.S. electricity system has changed in many ways since 1935, and Congress might choose to consider reevaluating the authority.

One potential aspect for congressional consideration is the duration of DOE emergency orders, especially in relation to critical resources identified pursuant to E.O. 14262. Under current law, and assuming such orders might result in a conflict with environmental requirements, DOE could potentially reissue its emergency orders every 90 days for an indeterminate amount of time. Repeated emergency orders may raise feasibility questions, such as whether successive emergency orders would be upheld by the courts or whether power plant owners would make long-term investments to maintain power plants that are operating primarily under emergency orders.

Congress could consider evaluating and clarifying via legislation whether the Section 202(c) authority is better reserved for short-term situations or whether application to long-term situations is appropriate. Some backers of power plants at risk of retirement (e.g., coal-fired power plants) might support extended emergency orders based on long-term economic considerations. At the same time, some backers of power plants with low greenhouse gas emissions (e.g., solar generators) might support extended emergency orders based on long-term environmental considerations. Others might prefer to limit DOE's emergency authorities to short-term situations. A more limited role for DOE in electricity system operations allows for greater use of market forces and reliance on local- and state-level processes to prepare for and respond to emergencies.

[12] PJM, "PJM Statement on the U.S. Department of Energy 202(c) Order of May 30," press release, May 31, 2025, https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.

Another potential aspect for congressional consideration is the definition of "emergency" in the context of Section 202(c). Current law gives DOE broad discretion in determining what constitutes an emergency. Congress could consider whether this level of discretion is appropriate, or whether additional (or alternative) statutory direction would better serve current system needs.

As noted above, some supporters of specific kinds of power plants might view sustained economic conditions or environmental impacts as emergencies that warrant DOE action. Those situations would appear to be novel exercises of DOE authority under Section 202(c), if DOE were to interpret them in such a way. Amendments to the Federal Power Act could clarify congressional intent regarding use of DOE's emergency authority in response to those situations or any other long-term situation.

Other stakeholders might wish to limit DOE's discretion in when to issue emergency orders—for example, by modifying the currently broad statutory language or by requiring additional review by FERC or another entity.

A third potential aspect for congressional consideration is the scope of interventions allowed under the emergency authority. Current law allows DOE to order almost any change in operation of the electricity system.

Emergency orders between 2000 and 2024 directed either the operation of certain generators as needed for reliability or the temporary interconnection of the main Texas grid with neighboring regions' grids. One of DOE's May 2025 emergency orders requires Puerto Rico's local utility to conduct vegetation management activities.

One operational consideration that has not been tested under DOE's emergency authority (at least not in the orders available on DOE's website) is the curtailment of certain generators. Curtailment occurs when a grid operator directs a generator to reduce its output or cease operating altogether for a certain amount of time. Curtailment is sometimes necessary when generation levels in a given location exceed the transmission system's capacity to transmit energy out of that location.

Congress could evaluate the appropriateness of DOE's currently broad discretion to order interventions in the operation of the electricity system. Amendments to the Federal Power Act could clarify what kinds of interventions DOE may require.

Author Information

Ashley J. Lawson
Specialist in Energy Policy

Disclaimer

This document was prepared by the Congressional Research Service (CRS). CRS serves as nonpartisan shared staff to congressional committees and Members of Congress. It operates solely at the behest of and under the direction of Congress. Information in a CRS Report should not be relied upon for purposes other than public understanding of information that has been provided by CRS to Members of Congress in connection with CRS's institutional role. CRS Reports, as a work of the United States Government, are not subject to copyright protection in the United States. Any CRS Report may be reproduced and distributed in its entirety without permission from CRS. However, as a CRS Report may include copyrighted images or material from a third party, you may need to obtain the permission of the copyright holder if you wish to copy or otherwise use copyrighted material.

U.S. Government Accountability Office

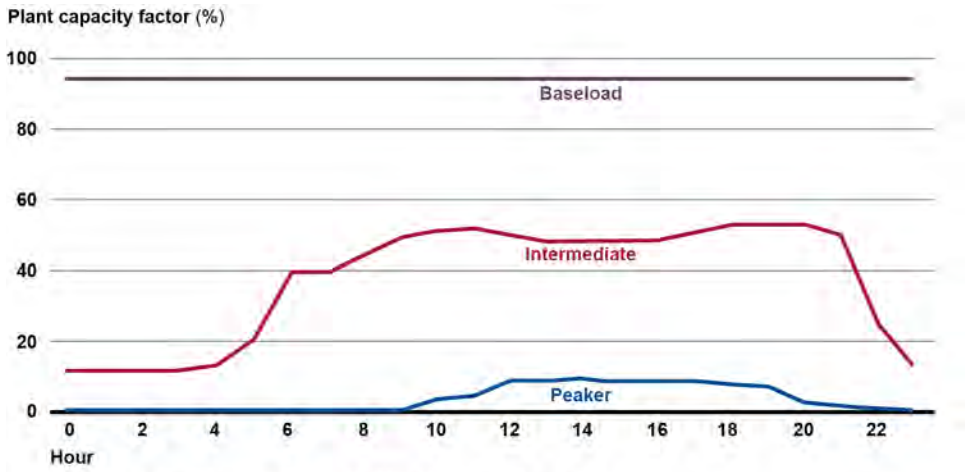
Electricity: Information on Peak Demand Power Plants

GAO-24-106145
Q&A Report to Congressional Requesters
May 21, 2024

Why This Matters

Peaker power plants are part of the U.S. energy infrastructure and help meet peak electricity demand. Peak demand generally occurs at times during the day when cooling and heating needs are generally the highest among households. Peakers are used to supplement other types of power plants, such as baseload plants, which run consistently throughout the day and night, and intermediate plants, which run mostly during the day and less at night (see fig. 1).

Figure 1: Illustrative Example of Annual Average Hourly Capacity Factors, by Plant Type



Source: GAO Analysis of Environmental Protection Agency data. | GAO-24-106145

Note: A plant's capacity factor is the percent of energy it produced of the total energy it could have produced during a certain time frame if it operated continuously at full power.

Peakers may be less efficient than other types of plants—such as intermediate and baseload plants—because they undergo frequent startups using comparatively large amounts of fuel. Further, environmental advocates and some congressional leaders have expressed concerns that peakers may also negatively affect the air quality in communities—which may be historically disadvantaged or disproportionately low income—around the plants.

We were asked to examine pollution from peakers across the nation. We are providing information on the number and locations of peakers in the U.S.; the proximity of peakers to disproportionately low-income, and historically disadvantaged racial or ethnic populations; the extent to which they emit pollutants and how these pollutants affect the health of people exposed; alternatives for replacing them; and potential challenges of replacing them.

Key Takeaways

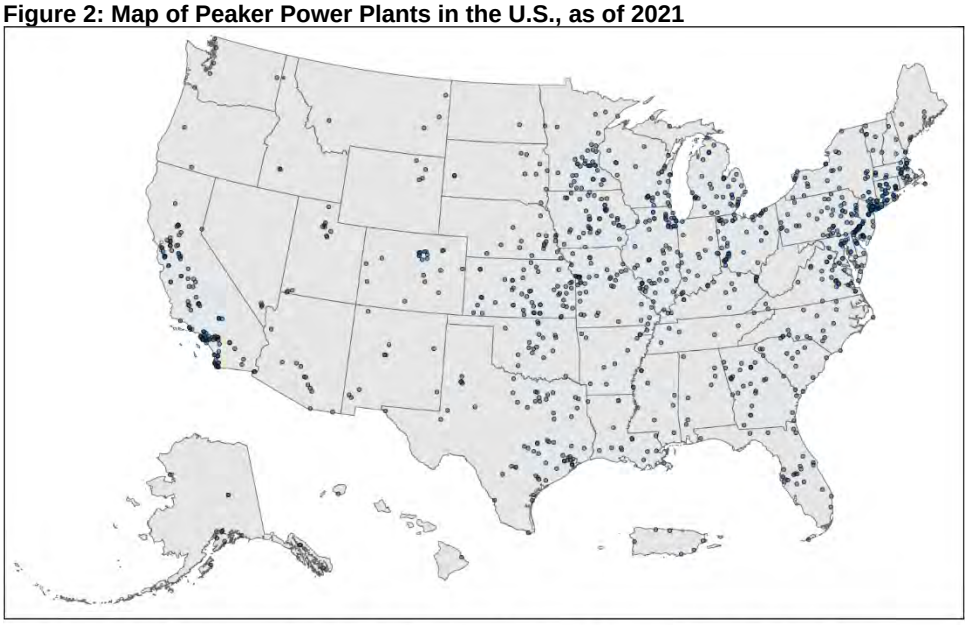
- Historically disadvantaged racial or ethnic communities tend to be closer to peakers.

- Fossil-fueled peakers are primarily fueled by natural gas and emit air pollutants associated with various negative health effects, including on respiratory, cardiovascular, and nervous systems.
- Alternatives are available that could potentially replace or provide similar services as peakers, but we identified challenges for their use related to costs, reliability, space, and location.

How many peakers are there in the U.S., and where are they located?

We identified 999 peakers in the U.S. in 2021, based on our analysis of Environmental Protection Agency (EPA) data (see fig. 2).[1] For the purpose of our report, we generally define peakers as plants that use fossil fuels, including natural gas, coal, and oil; have a capacity factor (the percent of energy produced over a certain time frame, out of what could have been produced at continuous full power operation) of 15 percent or less; and have a nameplate capacity (the designed full-load sustained output of a facility) of greater than 10 megawatts (MW) of electricity.[2] Most of these peakers are fueled by natural gas (see table 1). In 2021, these peakers accounted for 3.1 percent of annual net generation and 19 percent of total nameplate capacity for all power plants.

Figure 2: Map of Peaker Power Plants in the U.S., as of 2021



Source: GAO analysis of Environmental Protection Agency Emissions & Generation Resource Integrated Database (eGRID). | GAO-24-106145

Note: Alaska, Hawaii, and Puerto Rico are shifted for display purposes. We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity. Areas with multiple peakers appear darker than those with only one. This map does not identify whether there is any statistically significant spatial association or differentiate whether peakers are more concentrated in certain geographies relative to underlying population size.

Table 1: Total Net Electricity Generation and Total Nameplate Capacity of Peaker Power Plants, by Primary Fuel Type, 2021

Plant primary fossil fuel type	Number (%)	Total net generation (MWh)[a] (%)	Total nameplate capacity[b] (MW)
Natural gas	698 (69.87)	106,791,342 (82.75)	190,373
Oil	267 (26.73)	2,646,700 (2.05)	23,991
Coal	33 (3.30)	19,617,924 (15.20)	22,904
Other[c]	1 (0.10)	-9,824 (0.00)[d]	99
Total	**999 (100)**	**129,046,142 (100)**	**237,367**

Source: GAO analysis of Environmental Protection Agency data. | GAO-24-106145

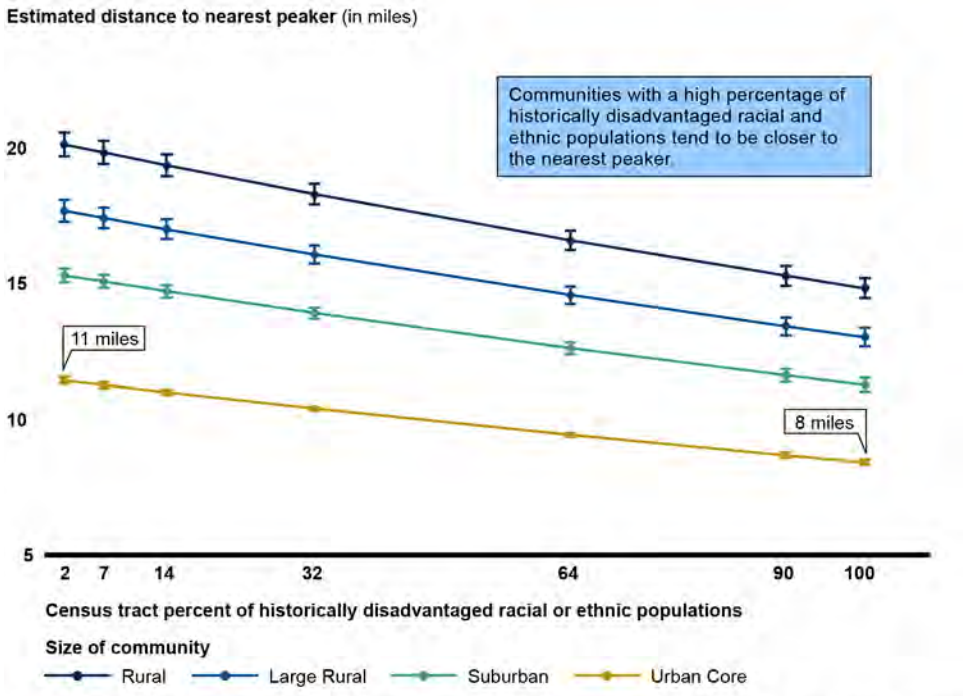
Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity.

[a]MWh = megawatt hour
[b]Nameplate capacity is the maximum output of electricity a power plant can produce without exceeding design thermal limits.
[c]This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[d]This plant has a negative net generation because electricity consumed by the plant exceeds the gross generation of the plant.

How closely are peakers located to historically disadvantaged and low-income communities?

We found that historically disadvantaged racial or ethnic communities (i.e., census tracts with higher percentages of historically disadvantaged racial or ethnic populations) are associated with being closer to peakers (see fig. 3).[3] To perform this analysis, we developed a statistical model to assess how community demographics are associated with proximity to peakers.[4] We tested this model with four alternative definitions of peakers and found that historically disadvantaged racial or ethnic communities are associated with being closer to peakers for all four definitions.[5] For example, based on our model and main definition of a peaker, a community that is 71 percent historically disadvantaged is expected to be 9 percent closer to the nearest peaker than the average community, which is 40 percent historically disadvantaged.[6] In addition, we found that the estimated distance to the nearest peaker varies according to population density, where urban communities have smaller estimated distances to the nearest peaker when compared to otherwise similar rural or suburban communities.

Figure 3: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Historically Disadvantaged, by Population Density



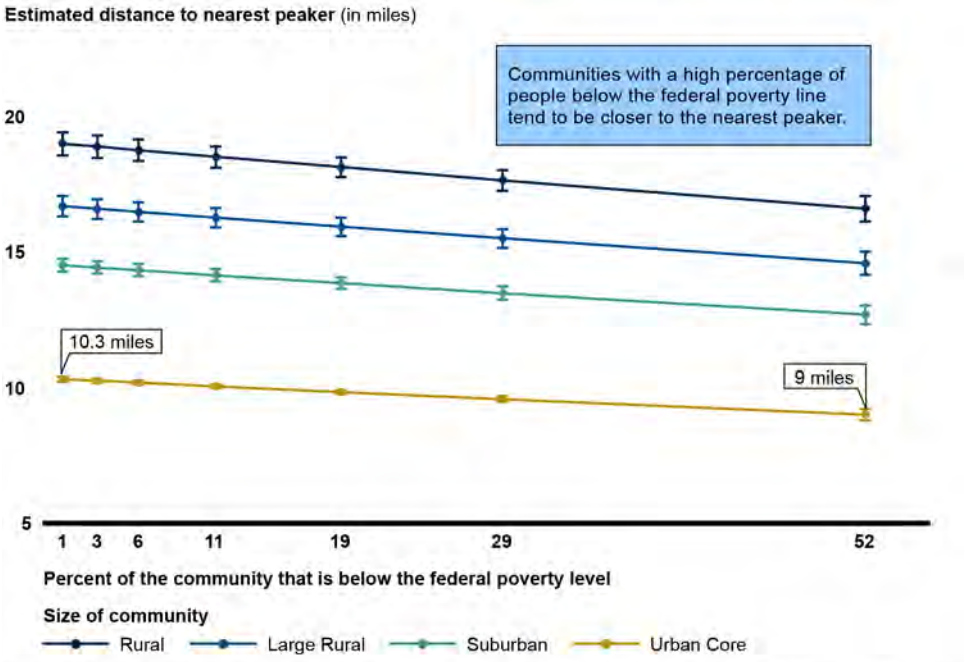
Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

We found mixed results for income. Specifically, for three of our four definitions of a peaker, we found that communities with higher percentages of people below

the federal poverty level were statistically significantly closer to the nearest peaker (see fig. 4).[7] Income was not statistically significant for our fourth definition.[8]

Figure 4: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Below the Federal Poverty Level, by Population Density



Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results for three definitions, but insignificant results for one definition. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

To what extent do peakers emit pollutants, and how can these pollutants affect the health of people exposed?

When operating, peakers emit similar types of pollutants to other power plants that also use fossil fuels, and these pollutants are associated with various negative health effects, according to existing literature.

Pollutants

Compared to non-peakers, peakers emitted more pollutants—such as nitrogen oxides and sulfur dioxide—per unit of electricity generated, but fewer total annual pollutants in 2021, according to our analysis of EPA data (see table 2).[9] In other words, peakers emit less in total because there are fewer peakers and they operate less frequently overall than non-peakers. However, when they do operate, they emit more pollution per unit of electricity produced. For example, the median sulfur dioxide emission rate for natural gas fueled peakers was 1.6 times more per unit of electricity generated than the median emission rate for non-peakers. Conversely, total annual sulfur dioxide emissions from peakers were 96.8 percent lower than total non-peaker annual sulfur dioxide emissions. Overall, peakers contributed 3 percent of the total annual sulfur dioxide emissions and 9 percent of total annual nitrogen oxide emissions.

Table 2: Sulfur Dioxide and Nitrogen Oxide Emissions from Fossil-fueled Peaker and Non-peaker Power Plants with Nameplate Capacity Greater than 25 MW, 2021

	Fuel Type	Peaker	Non-peaker
Median sulfur dioxide emission rate (pounds per megawatt hour)	Natural Gas	0.008[b]	0.005
	Coal	2.487	1.308
	Oil	4.218	2.174
	Other[a]	—	0.027
	All fuel types	**0.009**	**0.008**
Median nitrogen oxides emission rate (pounds per megawatt hour)	Natural Gas	0.949[b]	0.156
	Coal	1.554	1.330
	Oil	15.014[b]	3.152
	Other	—	0.670
	All fuel types	**1.272[b]**	**0.468**
Total annual sulfur dioxide emissions (tons)	—	32,111	1,014,787
Total annual nitrogen oxides emissions (tons)	—	83,874	885,345

Source: GAO analysis of Environmental Protection Agency data. | GAO-24-106145

Note: This analysis is limited to fossil-fueled plants with a nameplate capacity greater than 25 megawatts of electricity (1,605 plants) because plants of this size are required to report certain emissions, including sulfur dioxide and nitrogen oxides. Peakers in this analysis include plants with a capacity factor of 15 percent or less, and non-peakers include baseload and intermediate plants that supply more consistent power throughout the day. This analysis excludes plants that had incomplete emissions or generation data (57 plants).

[a]This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[b]Statistically, the median for peakers is significantly different from the median for non-peakers at the 0.05 level.

In addition to sulfur dioxide and nitrogen oxides, ground-level ozone and particulate matter are pollutants related to the operation of peaker plants. Ground-level ozone is formed through chemical reactions between nitrogen oxides—emitted by peakers—and volatile organic compounds. Particulate matter is a mixture of solid particles and liquid droplets found in the ambient air and can be directly emitted from power plants or formed by chemical reactions involving pollutants such as sulfur dioxide that are emitted by peakers.

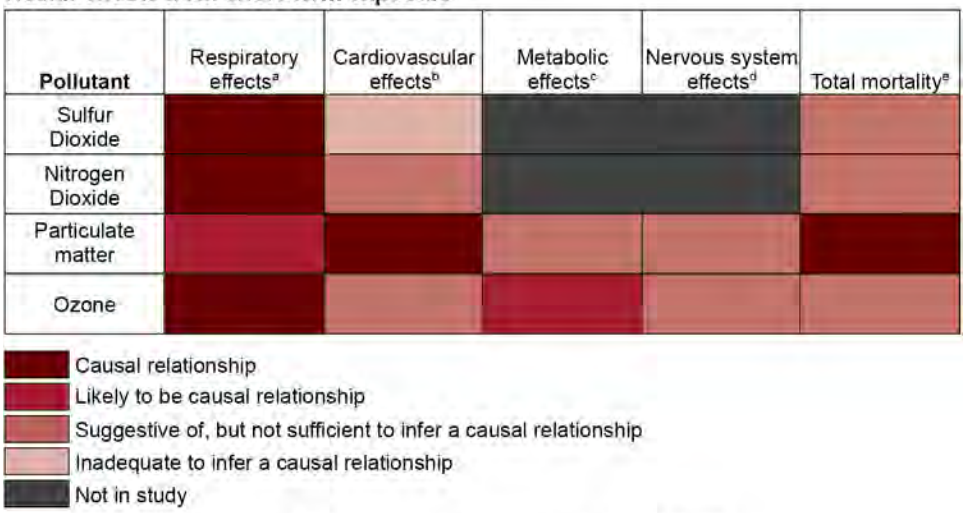
Peakers may have higher median emission rates per unit of electricity generated because of the nature of their operations. According to EPA, emissions generally increase under partial load conditions, which is how peakers operate.[10] Further, peakers typically do not have emissions control technologies, according to EPA officials.

Health effects

Multiple pollutants that are emitted from peakers and other plants are associated with various negative health effects for the people exposed, according to federal agency reports we reviewed.[11] In particular, EPA's Integrated Science Assessments identified causal relationships between short-term exposures to four key pollutants (nitrogen dioxide, sulfur dioxide, particulate matter, and ozone) and health effects that vary in degree of severity and duration (see fig. 5).[12] For instance, short-term exposure to sulfur dioxide—the indicator for sulfur oxides used in EPA's assessments—can lead to negative respiratory effects, such as decreased lung function, cough, chest tightness, and throat irritation.

Figure 5: EPA's Assessment of Causal Determinations for Relationships between Short-Term Exposure to Certain Air Pollutants and Health Effects

Health effects from short-term exposure



Source: Environmental Protection Agency (EPA) Integrated Science Assessments. | GAO-24-106145

Notes: Short-term exposure refers to time periods from minutes to 1 month.

We used sulfur dioxide and nitrogen dioxide in the figure because they are the indicators for sulfur oxides and nitrogen oxides, respectively, and sources of health effects studies for causal determinations in EPA's integrated science assessments.

The causal determinations related to particulate matter in the figure are associated with exposure to particles that are 2.5 microns or less in diameter. Causal determinations are also made for exposure to particles of other sizes (e.g., 10 microns or less).

We selected four of the six criteria air pollutants because we deemed them the most relevant pollutants to our analysis. This figure focuses on health effects of short-term exposures to these four pollutants. EPA's Integrated Science Assessments also include causal determinations for long-term exposures and for health effects that are not specific to short-term or long-term exposures (e.g., cancer and pregnancy and birth outcomes for particulate matter exposure).

[a]Respiratory effects include decreased lung function, cough, chest tightness, and throat irritation.
[b]Cardiovascular effects include heart attack, stroke, and changes in blood pressure.
[c]Metabolic effects include changes in blood glucose level and inflammation.
[d]Nervous system effects include brain inflammation and oxidative stress.
[e]Total mortality includes all nonaccidental causes of mortality and is informed by findings for the spectrum of morbidity effects (e.g., respiratory, cardiovascular) that can lead to mortality.

Additionally, mercury emitted from peakers, and other sources, is associated with neurological health effects, including tremors and disturbances of vision and cognitive performance, according to federal agency reports we reviewed.[13]

According to EPA, elevated temperatures can directly increase the rate of ground-level ozone formation, worsening air quality effects on human health. Elevated temperatures can also drive increased electricity demand, which is associated with the operation of peakers. As previously noted, the operation of peakers further increases ozone—and other pollutant—levels, exacerbating air quality issues and poor public health days.

What are some available alternatives that can potentially replace fossil-fueled peakers?

Available alternatives such as battery storage systems could potentially replace fossil-fueled peakers, according to studies we reviewed and stakeholders we interviewed (see table 3).[14] These alternatives could decrease emissions associated with peakers.

Table 3: Examples of Alternatives That Could Potentially Replace Fossil-fueled Peakers

Alternative type	Potential examples
Electricity generation and storage: Alternatives able to store or generate electricity to directly replace the output of peakers.	• Battery storage, which consists of rechargeable batteries charged during off-peak times, and discharged during times of peak demand. • Pumped hydroelectric storage is an energy storage system that pumps water to higher

	levels during off-peak times and releases said water to turn turbines and generate electricity during peak times. • Thermal energy storage is an energy storage system that stores thermal energy, which is released to power turbines during times of peak demand. • Renewable energy systems (e.g., wind and solar) may be paired with energy storage. For example, adding roof-top solar and battery storage to houses could reduce the demand for peakers in adjacent areas.
Transmission and distribution infrastructure improvements: Upgrades or expansions to increase the capacity of current infrastructure that transmits and distributes electricity. These upgrades or expansions may help enable existing underutilized plants to meet peak demand.	• Upgrading transmission lines by expanding the capacity of current lines or adding additional lines to solve bottlenecks in the grid and allow electricity to be moved to other locations. • Upgrading distribution systems by expanding or adding infrastructure to deliver electricity more efficiently.
Efforts to decrease consumers' use of power during peak times: Efforts to incentivize consumers to reduce or shift electricity use during times of peak use to off-peak times.	• Consumer based demand initiatives that provide lower prices for energy consumption during off peak hours, such as overnight electric vehicle charging. • Various energy efficiency programs.

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Note: These alternatives are not comprehensive. For example, there are other alternatives that are not ready for grid-scale deployment and are in early development stages, such as other types of energy storage technologies.

What are the potential challenges of replacing peakers?

Potential challenges to replacing peakers with non-emitting or non-combustion alternatives include challenges related to cost, reliability, and location, according to studies we reviewed and stakeholders we interviewed (see table 4).

Table 4: Potential Challenges Associated with Alternatives for Replacing Fossil-fueled Peakers

	Alternatives		
	Electricity generation and storage	**Transmission and distribution improvements**	**Efforts to decrease consumers' use of power during peak times**
Cost: some alternatives may have higher capital and operating costs compared to current fossil-fueled peakers	✓	✓	✓
Reliability: current alternatives may not be able to provide the same reliability of current fossil-fueled peakers	✓	—	✓
Location: alternatives may not be able to be installed because of space and location concerns	✓	✓	—

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Replacing peakers, some of which have already paid off their capital costs, will likely lead to additional up-front or operating costs compared to keeping the

existing peakers. Further, the U.S. Energy Information Administration (EIA) reported that solar and wind plants had higher average construction costs compared to natural gas-fired plants in 2023.[15]

Similarly, some alternatives may create reliability challenges. For the grid to be reliable, the energy resources in an area need to be able to supply power to meet peak demand for as long as it lasts, according to U.S. Department of Energy (DOE) officials. Some battery storage systems provide up to 4 hours of output, but peak demand may be longer in some areas. In contrast, a fossil-fueled peaker is only limited by fuel availability—a natural gas-fueled peaker could keep operating so long as natural gas is available.

Some alternatives may also run into space constraints or location concerns. For example, a densely populated urban community likely would not have sufficient space for a large renewable energy system paired with battery storage to help meet peak electricity demand.

In general, recognizing these challenges, some officials with whom we spoke identified trends that may lead to the continued use of fossil-fueled peakers. According to DOE officials, some U.S. peakers may not be able to be replaced with existing alternatives within cost, reliability, and location constraints. Combinations of electricity generation and storage technologies, transmission and distribution improvements, and efforts to decrease consumer's use of power during peak times may be too costly for consumers in some areas to provide an adequate level of grid reliability. Further, officials at two utilities noted that due to increased use of intermittent renewable resources on the grid (e.g., wind and solar power), the continued use of peakers to meet electricity demand may be necessary to maintain grid reliability. For example, the availability of sunlight for a solar installation may not match with peak demand in the evening when the sun goes down. Therefore, additional supplemental energy resources would be needed to fill the gaps and meet demand.

Agency Comments

We provided a draft of this report to DOE, EPA, and the Federal Energy Regulatory Commission (FERC) for review and comment. DOE and EPA provided technical comments, which we incorporated, as appropriate. FERC did not have any comments on the report.

How GAO Did This Study

To identify the number and location of peakers, we analyzed data from EPA's Emissions and Generation Resource Integrated Database and EIA power plant data. We generally define peakers as plants that use fossil fuels, have a capacity factor of 15 percent or less, and have a nameplate capacity of greater than 10 megawatts of electricity. In addition to the primary definition of peakers used in this report, we also considered several other definitions including plants with a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers).

To describe the relationship between community demographic characteristics (e.g., race, ethnicity, and income)[16] and distance to a peaker, we developed a statistical model that includes controls for population density (e.g., rural or urban), climate, and other factors. (See app. I for more detail.)

To identify air quality effects associated with peakers, we analyzed data from EPA's Emissions and Generation Resource Integrated Database to describe emissions and emission rates from peakers versus non-peakers. Our emission rate analysis focused on plants with a nameplate capacity greater than 25 MW because EPA regulations define that as the threshold for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program.[17] We

reported median emission rates because the median is robust to outliers. For example, the top three emitting plants for sulfur dioxide had emission rates in the hundreds of pounds per megawatt, and two of the three had nitrogen oxide emission rates in the thousands of pounds per megawatt. Officials from EPA and EIA told us these plants were likely used infrequently as peakers, or they generated electricity for on-site consumption.

To identify health effects, we reviewed reports from EPA, the Agency for Toxic Substances and Disease Registry, and the Centers for Disease Control and Prevention that assess the health effects of exposure to selected pollutants that are emitted from, or related to, emissions from power plants. We also conducted a systematic literature search of peer reviewed journals and grey literature published from 2013–2023 in databases such as ProQuest Research Library and Natural Science Collection, and Dialog Energy & Environment collection. We conducted an additional search to identify studies on the health effects of peakers in the same databases, and additionally PubMed, published from 2018–2023. Based on these searches, conducted from November 2022 to March 2023, we did not identify studies that looked specifically at health effects of peaker plants.

To identify available alternatives for and challenges to replacing peakers, and to inform our other reporting questions, we conducted a systematic literature search. We conducted searches of databases such as ProQuest Research Library, Harvard Kennedy School Think Tank Search, SCOPUS, and Dialog Energy and Environment collection to identify studies and grey literature published between 2013 and 2023 that were relevant to our research objectives. We performed these searches from November 2022 to March 2023. Additionally, we reviewed studies recommended to us by stakeholders.

To inform all our questions, we also interviewed federal officials from DOE, EPA, and FERC, and state officials from California, Georgia, Indiana, New York, and Texas. We selected these states based on their geographic diversity and electricity market structure (e.g., traditionally regulated or deregulated). We also interviewed stakeholders representing 13 industry and nongovernmental organizations with a diversity of perspectives about peakers. The sample of officials and stakeholders we interviewed is non-generalizable.

We used data from EPA, EIA, and the U.S. Census Bureau. We reviewed information about the data and the systems that produced them, and interviewed agency officials knowledgeable about the data. We requested and received written responses about data reliability from EPA and EIA. We determined that the data were sufficiently reliable for the purposes of our reporting objectives.

We conducted this performance audit from July 2022 through May 2024 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

List of Addressees

The Honorable Jamie Raskin
Ranking Member
Committee on Oversight and Accountability
House of Representatives

The Honorable Alexandria Ocasio-Cortez
House of Representatives

The Honorable Yvette D. Clarke
House of Representatives

We are sending copies of this report to the appropriate congressional committees, the Secretary of Energy, the Administrator of EPA, and the Chairman of FERC. In addition, the report is available at no charge on the GAO website at https://www.gao.gov.

GAO Contact Information

For more information, contact: Frank Rusco, Director, Natural Resources and Environment, RuscoF@gao.gov, (202) 512-3841.

Chuck Young, Managing Director, Public Affairs, YoungC1@gao.gov, (202) 512-4800.

A. Nicole Clowers, Managing Director, Congressional Relations, ClowersA@gao.gov, (202) 512-4400.

Staff Acknowledgments: Quindi Franco (Assistant Director), Andrew Moore (Analyst-in-Charge), Adrian Apodaca, Mark Braza, Katherine Chambers, Noelle Du Bois, William Gerard, Michael Kendix, Mollie Lemon, Andony Payne, Caitlin Scoville, Amber Sinclair, and Sonya Vartivarian.

Connect with GAO on Facebook, Flickr, Twitter, and YouTube. Subscribe to our RSS Feeds or Email Updates. Listen to our Podcasts.

Visit GAO on the web at https://www.gao.gov.

This work of the United States may include copyrighted material, details at https://www.gao.gov/copyright.

Appendix I: Technical Appendix

To assess the relationship between the distance to the nearest peaker and the demographic characteristics of a community (i.e., census tract), we developed an ordinary least squares regression model where the outcome is distance and the covariates are the demographic characteristics of a community. These characteristics are the percent of a community that are from historically disadvantaged racial or ethnic populations and percent of a community at or below the federal poverty level. We also controlled for the community's climate, population density, and distance to the nearest power plant.

The resulting coefficients from our model allowed us to

- describe whether there was a statistically significant relationship, and if so, the direction of the relationship. For an otherwise similar community and for significant coefficients, a negative coefficient means communities with higher values of the covariate are associated with being closer to a peaker, whereas a positive coefficient means they are further.
- quantify the estimated distance in miles to the nearest peaker for communities with higher rates of disadvantaged populations and for those with lower rates of this demographic, but that are otherwise similar.
- estimate the percentage decrease in distance to the nearest peaker for a community that is "above average" on a demographic, compared to an otherwise similar, but average community. Note we define "above average" as one standard deviation above the sample value of that demographic.

Model Variables/Data Sources

- Distance. We assigned to each community the distance between its central point and the central point of the nearest peaker's property, and this formed the outcome of our model. Similarly, we assigned to each community the distance between its central point and the nearest power plant, which was included as a control in our model. We used great circle distances.
- Demographics. We used American Community Survey (ACS) 2021 5-year estimates for the percent of people in a community who are below the federal poverty level and the percent of people in the community who are from historically disadvantaged racial or ethnic populations. Specifically, individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races.
- Climate. We included the county level heating and cooling degree days from 2017–2019 as indicators of electricity demand for heating and cooling. These indicators are intended to control for climate variations within states in our model. These data are not available for Alaska or Hawaii; therefore, any models with climate data excluded these states. We assessed models that were otherwise similar, but that excluded climate data (hence included Alaska and Hawaii), and the results were consistent. We calculated county level averages using data accessed from Columbia University on daily minimum and maximum temperatures on a 2.5x2.5-mile grid for the contiguous United States.
- Population density. We used U.S. Department of Agriculture (USDA) Economic Research Service (ERS) 2010 rural/urban commuting area codes (RUCAs), the most recently available data, with a four-category classification scheme based on Secondary RUCA Codes to classify each tract's population density.

    - We associated the 2019 USDA ERS tract codes with 2020 U.S. Census tracts using the U.S Census tract relationship files between the 2020 census tract entities and the 2010 tract entities.
    - In cases where there is more than one record for a 2020 tract, we select the tract that has the largest area of intersection.
- Definition of peakers. We identified plants as peakers using each of the four definitions described and ran separate models for each definition. To capture potential variation within a plant in recent years, the peaker status in our regression is based on 2018–2021 Environmental Protection Agency (EPA) data.

Model Specifications. We took several steps to assess the validity and sensitivity of our models.

- Statistical significance was determined at the 0.05 level of significance.
- Our distance and climate measures were on the logarithm scale to satisfy model assumptions, such as normality of errors, and to scale the effect of these factors and account for non-linearity.
- We used robust standard error estimation.
- We included fixed-effects for states to account for state-to-state variation.
- We assessed models that were otherwise similar to our primary model, but that excluded climate, and results were consistent. This allowed us to assess the sensitivity of our results when including Alaska and Hawaii, states that did not have weather data.
- We examined the four different definitions of peaker described in this report, and conclusions regarding race or ethnicity and population density were consistent across peaker definitions, but conclusions regarding poverty were inconsistent. In particular, models that did not factor in the plant startup time when defining a plant as a peaker resulted in a significant association with poverty, whereas only one definition of peaker that incorporated plant startup time was significant for the primary definition of poverty.
- We examined an alternative specification of race and ethnicity that separately accounted for race and ethnicity within the model. The results were consistent with our primary model and models that used alternative definitions of peaker.
- We examined an alternative specification of poverty that examined the percent of a community that was at twice the federal poverty level, and results were again inconsistent for different definitions of peakers.
- While we chose to examine race, ethnicity, and poverty, other measures of vulnerability exist, and are often correlated. Therefore, similar results might be discovered when examining other measures of vulnerability. Some of these measures—such as the ACS 5-year estimates for percent of a tract that speaks English less than “very well,” or the Council on Environmental Quality (CEQ) Climate and Economic Justice (CEJ) Screening Tool—have large margins of error, do not assess margins of error, or have higher rates of missingness when compared to our selected demographics. Additionally, the CEQ Screening Tool uses the census tract boundaries from 2010 because many of the data sources in that tool use the 2010 census boundaries, but those boundaries are not consistent with most recently available 2020 U.S. Census and ACS demographics. Further, the CEQ Screening Tool uses a binary classification of

communities as “disadvantaged” or “not” based on indicators of burdens, but other classifications exist. We chose to use continuous measures of the proportion of population in different race, ethnicity, and poverty groups to assess the association between communities with a range of percentages, from low or high, of their populations with these demographics, rather than using a definitive, yet subjective, classification of a community as “disadvantaged” or “not.”

Limitations. We took several steps to assess the validity and sensitivity of our models, but certain limitations remain. Importantly, our measure of distance does not include other aspects—such as stack height, wind speed, or wind direction—that play important roles in the dispersion of pollutants and potential populations exposure. In addition, although we include some variables to control for factors that could influence the findings, it is possible that other controls might be important and were not accounted for in our model. Inclusion of a state fixed-effect partially addresses this by controlling for factors that vary by state. Still, our findings of associations between distance to peakers and historically disadvantaged racial and ethnic communities does not imply any causal relationships.

Endnotes

[1]2021 data was the most recent year of data available from EPA.

[2]There is no standard definition of a peaker plant. We considered several other definitions for peakers in our analysis. These included plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers).

[3]We use the terms “historically disadvantaged racial or ethnic populations” and “historically disadvantaged communities” to include individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races. Census tracts are small, relatively permanent statistical subdivisions of a county.

[4]Executive Order 13985 of Jan. 20, 2021, “Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,” 86 Fed. Reg. 7009 (Jan. 25, 2021), charged the federal government with advancing equity for all, including communities that have long been underserved, and identifying and overcoming systemic barriers to opportunity for such communities in federal policies and programs. We chose race and ethnicity, and poverty as two dimensions of disadvantage. Both measures are components of the EPA’s Environmental Justice Screening and Mapping Tool. See appendix I for additional details.

[5]In our model, we primarily focus on peakers with a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts, as previously noted. We also ran results with other definitions including plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers). We found consistent results in the relationship between race/ethnicity and distance to the nearest peaker regardless of definition.

[6]The value of 40 percent corresponds to our sample average for this demographic, whereas 71 percent corresponds to one standard deviation above the sample average.

[7]References to the “federal poverty level” in this document are based on the Census Bureau’s poverty threshold, which follows the Office of Management and Budget’s Directive 14. According to the Census Bureau, it uses a set of money income thresholds that vary by family size and composition to detect who is in poverty. If a family’s total income is less than that family’s threshold, then that family, and every individual in it, is considered to be in poverty. In our model, we look at the percent of families in a Census tract whose income in the past 12 months is below the federal poverty level.

[8]In the case of poverty, for peakers defined as plants with a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes, the association (regression coefficient) between a tract’s poverty rate and distance to peakers is insignificant at the 0.05 level.

[9]Our emission rate analysis focuses on fossil-fueled peakers and non-peakers with a nameplate capacity greater than 25 megawatts because that is a threshold defined in EPA regulations for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program. *See* 40 C.F.R. Part 75.

[10]Environmental Protection Agency, Combined Heat and Power Partnership, *Catalog of CHP Technologies*, September 2017.

[11]We conducted a literature search to identify health effects related to peakers specifically, but our literature search did not identify any such studies (e.g., studies that compare health effects based on proximity to peakers or attribution of ambient air pollution attributed to peakers). Our search strategy included conducting a systematic literature search of peer-reviewed journals as described in the section "How GAO Did This Study." We also inquired about published studies on the health effects of peakers during our interviews with agency officials and stakeholders. Our search identified some studies of the health effects related to retirements of coal fired power plants (for example, see Joan A. Casey, Deborah Karasek, Elizabeth L. Ogburn, Dana E. Goin, Kristina Dang, Paula A. Braveman, and Rachel Morello-Frosch, "Retirements of Coal and Oil Power Plants in California: Association with Reduced Preterm Birth Among Populations Nearby," *American Journal of Epidemiology*, vol. 187, no. 8 (2018), 1586-1594, DOI 10.1093/aje/kwy110). We did not conduct a systematic review of such articles because they are not peaker-specific, and because a low percentage of peakers are coal-fired.

[12]EPA's Integrated Science Assessments integrate information on criteria pollutant exposures and health effects from controlled human exposure, epidemiologic, and toxicological studies to form conclusions about the causal nature of relationships between exposure and health effects. For more information, see the EPA Preamble for Integrated Science Assessments at Preamble To The Integrated Science Assessments (ISA) | ISA: Integrated Science Assessments | Environmental Assessment | US EPA (accessed 8/30/2023).

[13]Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Mercury: Draft for Public Comment,* CS274127-A (April 2022). Environmental Protection Agency, National Center for Environmental Assessment, *Mercury, Elemental*, Integrated Risk Information System (IRIS) CASRN 7439-97-6.

[14]The discussion in this section applies to fossil-fueled peakers as defined above–those with a capacity factor less than 15 percent and a nameplate capacity greater than 10 megawatts—as well as to fossil-fueled peakers more broadly.

[15]U.S. Energy Information Administration, US Construction Costs Dropped for Solar, Wind, and Natural Gas-fired Generators in 2021 (October 3, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60562.

[16]See appendix I for additional details.

[17]*See* 40 C.F.R. Part 75.

EIA-923							EIA-860					
Plant Id	Plant Name	Operator Name	Operator Id	Plant State	Net Generation (Megawatthours)	YEAR	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Minimum Load (MW)	Time from Cold Shutdown to Full Load
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	136,387	2024	265.2	0.850	260.0	260.0	100.0	OVER
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	14,384	2024	378.8	0.770	279.8	280.0	100.0	OVER
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	8,077,299	2024	916.8	0.860	790.7	789.3	350.0	OVER

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-7

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and petition for rehearing of the Department of Energy's ("DOE") May 23, 2025, Order No. 202-25-7 ("Renewed Order," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant." The Renewed Order is in effect from 00:00 Eastern Daylight Time (EDT) on August 21,2025, and expires at 00:00 EDT on November 19, 2025.

This Renewed Order is dated August 20, 2025, and continues the prior DOE Order No. 202-25-3, which directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date through August 20, 2025, expiring at 00:00h on August 21, 2025 (the "Original Campbell Order)."

Pursuant to the Federal Power Act ("the Act") and Department procedures applying it to

---

[1] All Exhibits are lettered and attached; to be submitted in separate serial emails to the DOE's AskCR <askcr@hq.doe.gov> account.

petitions for rehearing, the States hereby file this timely request for rehearing of DOE's Renewed Order. The Renewed Order extends the Original Order, perpetuating the Original Order's flawed analyses, faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO") for the summer months of 2025, and unlawful directives. This Order exceeds DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to meet the purported need. It should be rescinded.

.

TABLE OF CONTENTS

Motion to Intervene 4

Petition for Rehearing 11

I. Overview and Concise Statement of Error 11

II. Legal Background 13

III. Statement of Issues 14

IV. MISO's Robust Capacity and Planning Projections are Adequate to Ensure Reliability. 17

V. Argument 20

A. The Renewed Order is not supported by substantial evidence demonstrating the existence of an actual emergency and does not demonstrate reasoned decision-making. 20

B. The Renewed Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371. 36

C. The Renewed Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1). 40

D. The Renewed Order exceeds DOE's authority because it does not set hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3). 41

E. The Renewed Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states. 42

F. The Renewed Order is unreasoned, arbitrary, and capricious because its directive for "economic dispatch" is inherently contradictory with the needs to meet an actual emergency. 46

G. The purported emergency is pretext for a prejudged outcome. 52

Conclusion 55

MOTION TO INTERVENE

The States[2] move to intervene in this proceeding and thereby to become parties for purposes of Section 313l of the Act, 16 U.S.C. § 825l. The States have an interest in and are aggrieved by the Renewed Order (Ex. A) in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U.S. ___ (2025) (slip op., at 3–8) (defining an "adversely affected or aggrieved" party within the APA as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities regulated by the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator ("ISO") in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the "air traffic controller" for the grid in its territory,[3] meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

---

[2] *See* Minn. Stat. § 8.01 ("The attorney general shall appear for the state in all causes in the supreme and federal courts wherein the state is directly interested; also in all civil causes of like nature in all other courts of the state whenever, in the attorney general's opinion, the interests of the state require it.).

[3] "Meet MISO," https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/what-we-do/ (last visited June 23, 2025).

On May 23, 2025, the DOE issued the Original Campbell Order pursuant to section 202(c) of the Federal Power Act to MISO. *See* Ex. B; *see also* 16 U.S.C. § 824(c)(1). The Order directed MISO, in coordination with Consumers Energy, the owner of the plant, to ensure that the Campbell Plant remained available for operation during the summer season; expiring on August 20, 2025. *Id.*

This eleventh-hour Original Campbell Order disrupted a longstanding planning sequence handled by state authorities and submitted to MISO. Consumers Energy had already announced its plan to retire the Campbell Plant in 2021, and MISO approved that retirement plan three years ago, in March 2022.[4]

Minnesota and Illinois timely submitted a Petition for Rehearing of the Original Order on June 23, 2025. Ex. D. DOE did not act on that petition within 30 days; and later issued that it had been denied by operation of law given the passage of time. Ex. C. Minnesota and Illinois filed a Petition for Review in the D.C. Circuit Court of Appeals (No. 25-1162, consolidated with 25-1159 and 25-1160) on July 28, 2025.

On August 20, 2025, the DOE issued the Renewed Order requiring MISO and Consumers Energy to ensure that the Campbell Plant "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant." The Renewed Order is in effect from 00:00 Eastern Daylight Time (EDT) on August 21,2025, and expires at 00:00 EDT on November 19, 2025.

On September 8, 2025, DOE issued a document fashioned as "ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING." Ex. E.

---

[4] *See* Consumers Energy, "2021 Clean Energy Plan," https://www.consumersenergy.com/-/media/CE/Documents/company/IRP-2021.pdf (last accessed June 23, 2025).

Adverse Effects

The States will be adversely affected by the Renewed Order in many of the same ways that they were harmed by the Original Campbell Order. The Renewed Order prevents the planned retirement of the Campbell Plant, with consequent negative impacts on the States.

First, households and businesses in the States, and the States as consumers in their own right, will pay higher electricity bills as a result of the Renewed Order's imposition of costs and cost-recovery to the States. By ordering the Campbell Plant to take all steps necessary to be available and ordering MISO to take all steps necessary for the Campbell Plant to provide economic dispatch, costs are already being incurred and more costs will continue to be generated. Notably, the age of the units is concerning for costs, and Consumers Energy projected in 2021 that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs.[5] The Renewed Order would likely require at least a portion of capital expenditures and major maintenance costs, which will drive up costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Renewed Order provides that cost recovery is available to Consumers Energy through Federal Energy Regulatory Commission ("FERC") proceedings, (¶E). Consumers Energy already initiated a cost recovery complaint before FERC on the Original Campbell Order,[6] asking to allocate costs (net of market revenues) across

---

[5] In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief, MPSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala on Behalf of Consumers Energy Company at 3 (Oct. 2021).

[6] FERC Docket: EL25-90.

all of MISO Zones 1 through 7 (which includes Minnesota and Illinois). Consumers Energy asked that these costs be apportioned according to load, which would assign costs to the States. MISO filed its answer indicating its general support for adjusting its tariff to account for Consumers Energy's cost recovery petition, meaning the costs will be charged to the States according to their respective share of load. FERC granted cost recovery on August 15, 2025.

The Renewed Order will have substantially the same impact, and more if additional maintenance—deferred or otherwise—needs to be performed to keep the aging (and greatly deteriorated) Campbell Plant units online.

Second, the States will suffer environmental harms as a result of the Order. The Campbell Plant is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[7] among other pollutants. By extending the operations of the Campbell Plant beyond its planned retirement date, the Order increases the amount of pollution emitted in the state of Michigan and other MISO States, causing harm to the public health and welfare.[8] The States of Minnesota and Illinois share the upper Midwest region and Great Lakes environment with Michigan. Depending on weather, air emissions in Michigan impact conditions in Minnesota and Illinois. Further, Minnesota and Illinois have an interest in the Great Lakes ecosystem into which pollutants from coal-burning power plants such as mercury are deposited. Such pollution is harmful to state economies including fisheries and recreation, human health, and the environment in general. The Campbell Plant is situated on the shores of Lake Michigan across from Illinois, including the highly populated Chicago metropolitan area. Thus Minnesota and Illinois have an

[7] See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief., No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).
[8] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

economic, public health, and ecological interest in protecting their environment and natural resources from unnecessary pollution emanating from the Campbell plant. Minnesota and Illinois are harmed because the Order results in the unnecessary consumption of fuel that generates such pollution.

Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States by imposing significant additional costs for responsive actions, disaster recovery, and resiliency programs. Increased emissions threaten state climate goals and the States' ability to comply with federal and state air pollution requirements.

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.[9] Each of Minnesota's top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.[10] Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.[11] These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.[12] Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures.

---

[9] Minnesota Climate Trends, *Minnesota Department of Natural Resources* (2023), https://www.dnr.state.mn.us/climate/climate_change_info/climate-trends.html.
[10] *Id*.
[11] *Id*.
[12] *Id*.

The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal disaster declarations for large parts of the state.[13] From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.[14] The "Lost Winter" of 2023-2024 was the warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota's recreational economy.[15] These impacts will continue, and emissions from the Campbell Plant contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois' farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.[16] In other years, extreme precipitation has threatened Illinois' agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose

---

[13] "Extreme Rainfall Drenches Northeastern Minnesota," Minnesota Department of Natural Resources, https://www.dnr.state.mn.us/climate/journal/extreme-rainfall-northeast-mn-june-18-2024; "Extreme Rain and Flooding in Southern Minnesota, June 20-22," Minnesota Department of Natural Resources, (August 9, 2024), https://www.dnr.state.mn.us/climate/journal/extreme-rain-flooding-southern-minnesota-june-20-22.html; "Disaster information," Minnesota Department of Public Safety, https://dps.mn.gov/divisions/hsem/em-resources/disaster-information (last visited June 23, 2025).

[14] "Billion Dollar Weather and Climate Disasters, Minnesota Summary, *NOAA National Centers for Environmental Information*, Billion-Dollar Weather and Climate Disasters | Minnesota Summary | National Centers for Environmental Information (NCEI)," https://www.ncei.noaa.gov/access/billions/state-summary/MN.

[15] *Id*.

[16] Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/ (last visited May 23, 2025).

revenue.[17] Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois' 102 counties and the state logged 142 tornadoes—a new annual record.[18] These storms included a July 15, 2024 "derecho" that produced 100 mile-per-hour winds and 48 separate tornados.[19] In the Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 "double derecho" and a March 2023 storm.

Moreover, the States have an interest given their primary responsibility for resource planning and ensuring that there will be adequate and reliable electricity generation. The processes that States employ to ensure reliability—which takes into account planned retirements, new generation projects, transmission infrastructure, and meeting consumer demand—are both sophisticated and robust. The Renewed Order harms Minnesota and Illinois by usurping the traditional role that states play in generation planning and resource adequacy.

---

[17] University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). *See also* U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).

[18] Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/ (last visited May 23, 2025).

[19] National Weather Service, July 15, 2024, Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20the%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). *See also* David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by 'Ring of Fire', WBEZ CHICAGO, available at https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15 (last accessed May 23, 2025)

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

The challenged Renewed Order compounds the error of the Original Order in that it declares an emergency based on a shortage of electric energy generation when there is no emergency. Even if there is an emergency, the Renewed Order imposes several requirements that are inconsistent with and exceed DOE's legal authority. And even if DOE has the authority to impose the requirements, they are not directed to actions that will actually meet the purported emergency.

The challenged Renewed Order is premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025.

It first relies on the Original Order, which was fundamentally flawed and misstated the purported "evidence" on which it relied for all of the reasons set forth in the States' Petition for Rehearing, filed June 23, 2025. Ex. D.

The Renewed Order continues to misconstrue the source material on which it relies and still concludes only that there is a possibility of shortfalls. But it does not cite or rely on any evidence that there is any likelihood or probability that they will occur during the relevant timeframe of the Renewed Order.

The Renewed Order concludes that the evidence collected (and discussed below) supports the issuance of Order No. 202-25-3. It contends that the purported emergency will continue in the near term and is likely to continue in subsequent years. It declares—without any evidence identifying an emergency in the August 20 to November 19 timeframe—that the alleged emergency "could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety." Ex.

A at 7 (emphasis added). It then orders that MISO and Consumers Energy shall take "all measures necessary to ensure that the Campbell Plant is available to operate." And MISO must "take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." Further, it orders that the Campbell Plant operate according to times as determined by MISO. Importantly, the Renewed Order prohibits the Campbell Plant from being considered a capacity resource.

The Renewed Order was issued in error. The DOE did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency in general, be it far into the future or even in the August 20 to November 19, 2025, timeframe.

It starts from the proposition that there is only a "potential" for insufficient capacity that "could" result in a need for mitigation, which does not present an actual existing or imminent emergency. Section 202(c)'s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. This Renewed Order, however, requires the Campbell Plant to be "available to operate." Nothing in section 202(c) grants DOE authority to order a plant be available to operate without any demonstrated need identified by the states with primary resource planning authority, the utility operating the resource, or grid operator responsible for forecasting and coordinating adequate and reliable supply.

Even if an emergency did exist and DOE had the legal authority to issue the Renewed Order, directing the Campbell Plant to participate in the bidding market using economic dispatch would not rationally "best" meet the purported need (because there is no evidence the Campbell Plant can reasonably address any given future emergency need. This is because emergency responses do not require economic evaluation, and because the Campbell Plant takes so long to ramp up). The Renewed Order should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission[20] has authority to issue an order:

> [d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

16 U.S.C. § 824(c)(1). The same subsection states that the Commission may order "temporary connections of facilities" and "generation, delivery, interchange, or transmission of electric energy" that, in the Commission's "judgment will best meet the emergency and serve the public interest." *Id*. The next subsection, 16 U.S.C. § 824(c)(2), establishes that an emergency order must be limited to only those hours necessary to meet the emergency. It states:

> With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet

---

[20] The "Commission" refers to the Federal Power Commission (FPC), whose powers were transferred in 1977 to either the Secretary of DOE or the Federal Energy Regulatory Commission ("FERC"). 16 U.S.C. § 796(14); Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, 565-613 (1977). This transfer gave FERC the authority over "the interconnection, under section 202(b), of such Act [16 U.S.C. 824a(b)], of facilities for the generation, transmission, and sale of electric energy (*other than emergency interconnection*)." 42 U.S.C. § 7172(a)(1)(B) (emphasis added). However, this transfer also gave DOE "the function of the [FPC], or of the members, officers, or components thereof" except as provided in subchapter IV of the act. 42 U.S.C. § 7151(b). Because 42 U.S.C. § 7172(a)(1)(B) explicitly excludes emergency interconnection from FERC's authority, the authority over emergency interconnection has historically been delegated to DOE. However, the delegation of this emergency authority to DOE has not been consistently applied. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (1978), a petitioner objected to FERC's (not DOE's) failure to invoke emergency powers under 16 U.S.C. § 824a(c) and order utilities with excess capacity to supply the petitioner with energy. The court did not address whether FERC had the authority to declare an emergency to begin with. *Id*. Thus, whether FERC or DOE has the power to declare an emergency is inconclusive.

> the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Id. at § 824(c)(2).

The applicable regulations define "emergency," 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*.

10 C.F.R. § 205.371[21] (emphasis added).

III. Statement of Issues

Issue A: Did DOE have substantial evidence for the Renewed Order's declaration of an emergency, and did it exercise reasoned decision-making in declaring that an actual emergency exists?

No. DOE relied on evidence that did not identify any likelihood or probability that there would be a shortfall during the relevant timeframe of the Renewed Order's requirements—August 20 to November 19, 2025. Further, DOE failed to consider substantial countervailing evidence, including the MISO States' Integrated Resource Plans and MISO's PRA for the summer of 2025. The Renewed Order fails to identify any reasoned basis for concluding an

[21] DOE issued 10 C.F.R. §§ 205.370-379 pursuant to the Department of Energy Organization Act's transfer of emergency responsibilities to the Secretary of Energy.

actual emergency exists or is imminent, much less one that will occur between August 20 and November 19.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply situation. Did DOE exceed this authority where its Renewed Order is based on the nonspecific possibility that such a situation might occur over a period of several months—or in the 2027-2030 timeframe, well outside of the Renewed Order's applicability?

Yes. An actual "emergency" is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The Renewed Order does not address any sudden occurrence needing imminent response, nor does it identify any actual and specific insufficient supply situation. Instead, the Renewed Order focuses on vague non-summer needs and the potential for shortfalls several years away. Because the Renewed Order is not directed to any emergency at all, much less one occurring in the August 20 to November 19 timeframe, DOE lacks authority, and the Renewed Order is contrary to law.

Issue C. Section 202(c)(1) allows DOE to issue emergency orders requiring the "generation, delivery, interchange, or transmission of electric energy." Did DOE exceed this authority where its Order requires the Campbell Plant to take steps to be "available" to generate electricity and requires MISO to employ economic dispatch?

Yes. DOE's emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because the Order does not adhere to the types of actions allowed under section 202(c)(1), DOE lacks authority, and the Renewed Order is contrary to law.

Issue D. If DOE issues an order pursuant to 202(c)(1), then 202(c)(2) requires it to set limits on hours of operation and ensure that environmental impact is minimized. Did DOE exceed its authority by invoking section 202(c) to issue a Renewed Order that sets no specific hours of operation, places no limits on hours of operation, and adopts no specific requirements to minimize environmental impact?

Yes. The statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Renewed Order does not establish any limited hours for operation, instead deferring to MISO. The Renewed Order also does not meaningfully take steps to minimize adverse environmental impacts. Because the Renewed Order does not set any specific hours the Campbell Plant must run, and does not meaningfully minimize adverse environmental impacts, the Renewed Order violates the requirements of section 202(c)(2). The DOE is without authority, and the Renewed Order is contrary to law.

Issue E: The Federal Power Act reserves resource adequacy planning to the individual states. Did DOE exceed its authority where its Order directly compels a plant slated for retirement to take steps to be available to operate?

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). DOE's Order exceeds its authority by contradicting Michigan's resource plans. It also exceeds DOE's authority by purporting to engage in long-term resource planning for the years 2027-2030, which is a role reserved to the states. For both reasons, the Renewed Order is contrary to law.

Issue F: Even if DOE were correct that an emergency exists and that it had the authority to issue the Order, will the Order's requirements rationally meet the emergency?

No. Section 202(c) contemplates emergency orders that are precisely tailored to "best" meet the specific emergency. 16 U.S.C. § 824a(c). The Order's specific requirement for MISO to

take steps to effectuate "economic dispatch" of the Campbell Plant is not rationally related to the emergency it purports to address. Even during the peak days in June of 2025, MISO had adequate resources to generate power without the Campbell Plant's output—with capacity to spare. The Renewed Order does not explain how keeping the Campbell Plant available to run will meet any particular need when MISO has adequate resources at its disposal without the Campbell Plant. The Renewed Order, therefore, is without substantial evidence and lacks reasoned decision-making.

Issue G: Federal law prohibits agencies from prejudging the outcome of an action. Did the Secretary of Energy and the federal administration improperly prejudge the need for the Renewed Order?

Yes. As evidenced by public statements, the purported emergency is pretext for an improperly-prejudged outcome to preserve coal as a fuel for electrical generation.

IV. MISO's Robust Capacity and Planning Projections are Adequate to Ensure Reliability.

MISO is a regional transmission organization (RTO), an independent, non-profit, membership-based organization responsible for optimizing generation and transmission of electricity and ensuring the reliability of the electric power system within its region, consisting of nearly 3,000 generating units.[22] 18 C.F.R. § 35.34(a), (j)(1). MISO administers bulk or wholesale power markets that centrally commit and dispatch power to facilitate least-cost and reliable power production and delivery throughout the region. The wholesale markets within MISO signal and value power needs and identify the most economically efficient way—the least-cost approach where demand for energy equals the cost supplied—to meet them across the system.[23] MISO also

[22] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.
[23] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.

works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.[24] MISO uses advanced modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.[25]

MISO planned for adequate capacity during the summer of 2025: "As recognized by the Renewed Order, MISO's Planning Resource Auction ["PRA"] for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex. F at 2. It reports: "it is important to recognize existing processes have *cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order*." *Id*. (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*.

The long-planned retirement of the Campbell Plant is not an impediment to summer reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating

---

[24] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).

[25] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

units.[26] That trend is shown below in the bar graph (from MISO's 2023 Transmission Expansion Plan Report,[27] Ex. G at 35), which displays the retired capacity by generation type over time:

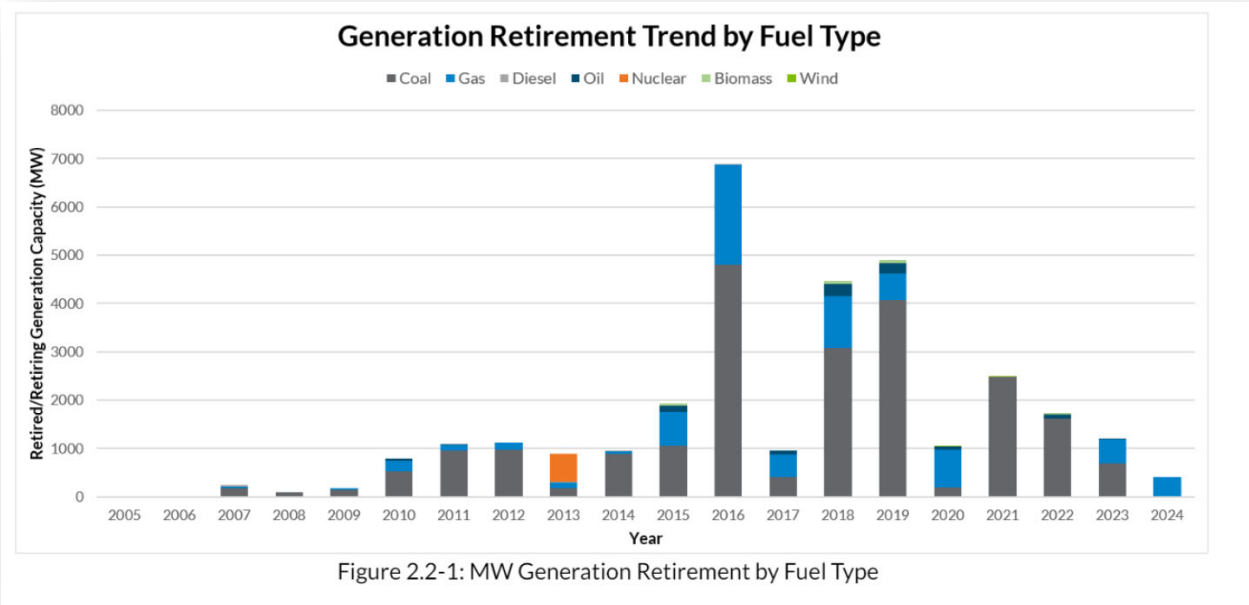


Figure 2.2-1: MW Generation Retirement by Fuel Type

Through use of generation capacity and transmission infrastructure planning, the addition of new capacity—in particular renewables, and the implementation of the other measures discussed above, MISO has been able to absorb these retirements and maintain overall system reliability. *Id*. at 34–35.

---

[26] *See also* MISO, *Approved Generator Retirements (Public) as of June 28, 2024* ("*Approved Retirements 2024*"), https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).

[27] MISO, *2023 Transmission Expansion Plan*, available at https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf.

V. Argument

A. The Renewed Order is not supported by substantial evidence demonstrating the existence of an actual emergency and does not demonstrate reasoned decision-making.

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE's determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 825l. After an objection has been brought before DOE, the Court may consider it with the understanding that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 16 U.S.C. § 825l. Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Duke Energy Corp. v. FERC*, 892 F.3d 416, 420 (2018). This standard implies deference to an agency's factual determinations. *See, e.g., id.*

DOE failed to point to substantial evidence of a current and unexpected emergency in the August 20 to November 19, 2025, timeframe during which the Renewed Order is in effect. The evidence DOE provided does, however, prove that there is currently no energy emergency and that there will not be an "unexpected emergency" that warrants this Renewed Order. MISO is well situated to deliver reliable power throughout its area in the fall of 2025.

In declaring the contrary, DOE relied on a NERC assessment that identified an elevated risk for potential capacity exceedance if an extreme weather event were to occur**.** But the Renewed Order makes too much out of too little—the "elevated" category is hardly a call for immediate and unnecessary emergency action. As the NERC assessment points out, MISO expects to have an existing certain capacity of 142,783 MW during the summer—which already factored in the assumption that the Campbell Plant would be retired and unavailable for the summer of 2025. That

projection also exceeds both expected demand and the reserve margin.[28] While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. To the contrary, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The "elevated risk" category is not tantamount to an emergency. Even though NERC used the term "elevated risk" for the possibility that there could be an operating reserve shortfall, NERC did not apply the "high risk" category to MISO and did not call for any retired plants to be brought back online. Ex. H. at 5. Moreover, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions. *Id*. at 16.

Perhaps most simply, the "elevated risk" designation is far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated an "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[29] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021. *Id*. Yet no

---

[28] MISO PRA, Results for Planning Year 2025-26 at 18 (Corrected May 29, 2025).
[29] *See* NERC*, Reliability Assessments,* https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited June 23, 2025).

energy shortage has occurred, and DOE has never imposed an emergency declaration until now (see *infra* regarding prejudgment and pretext).

In fact, the evidence before DOE cuts against the Renewed Order. This includes MISO's PRA for the summer of 2025, which found sufficient capacity throughout the region for the summer 2025 season. The PRA provides a strong conclusion that supply will be adequate. Ex. F. The press release announcing the PRA, (Ex. I), confirms "adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026)." Ex. I. And while "the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint." *Id*. The PRA was based on NERC's standard BAL-502-RF-03 (Ex. J), requiring assessment of "one day in ten year" loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO will have sufficient capacity through the summer of 2025. Exs. F, I. J. MISO's PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

Indeed, in MISO's Answer to the cost-recovery docket dated June 19, 2025, MISO highlights the PRA when it describes, with certainty, that it has planned for adequate capacity: In the FERC rate recovery proceeding, MISO wrote in its answer that it had sufficient capacity: "As recognized by the Order, MISO's PRA demonstrated sufficient capacity for all zones within the MISO Region." Ex. K at 2. MISO's Answer further writes, "it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order." *Id*. (emphasis added). And it goes on to describe its confidence that it has

already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*. This recent submission undermines DOE's conclusions in the order that MISO faces insufficient capacity.

And beyond the lack of supporting evidence, DOE also acted arbitrarily and capriciously by ignoring well-known and readily-accessible contrary information. For example, DOE failed to consider recent comments by MISO's Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC's purported concerns—these comments were cited in the States Petition for Rehearing of the Original Campbell Order. Ex. L. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has since been revised[30]) that included capacity shortfalls in 2025, noting that NERC's assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be "more than adequate," and that he had "no material concerns" over MISO's resource adequacy for the upcoming summer.

DOE also failed to consider MISO's history of strong performance through several extreme weather events including Winter Storms Elliot and Uri and did not credit MISO's proven track record of engaging in a variety of mechanisms to ensure grid reliability.

DOE further failed to acknowledge that no part of MISO is currently afflicted by any unexpected outage or extreme weather event, and the entire system is running as planned with no outages, unexpected demand, lack of fuel or water, or other such emergencies in place at the time of the Renewed Order.

---

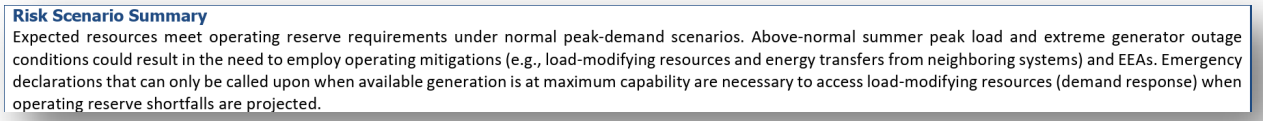
[30] NERC, *Statement of NERC's Long-term Reliability Assessment*, (June 17, 2025), available at https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx?utm_source=substack&utm_medium=email.

1. The materials cited in the Original Order do not support the existence of an emergency.

The evidence supporting the Original Campbell Order does not support the Renewed Order. The Renewed Order continues to rely on some of the same evidence that DOE cited in the Original Campbell Order, including the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Ex. H. That report does not identify any war, fuel shortage, or natural disaster. *Id*. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. Ex. H at 5. Here are NERC's main conclusions regarding MISO:

> **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.

Id. at 5. NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. Indeed, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions:



Id. at 16.

Second, the Renewed Order describes a sequence of resource retirements without acknowledging the replacement capacity that came online (or that is/was planned to come online) to offset those retirements. Ex. A at 2. In any event, NERC's 2025 Summer Reliability Assessment analysis already factored in an assumption that included those retirements including the Campbell Plant' slated retirement for the summer of 2025. Ex. H at 5, 16.

Third, the Renewed Order cites NERC's "elevated risk" determination. But the Campbell Plant's retirement was well known to MISO operators who accounted for the retirement in their robust resource planning processes (described in further detail herein). Indeed, the Renewed Order acknowledges that the retirement was already factored into MISO's own supply forecasts. *Id*. at 2. MISO's PRA (Ex. F), cited in the Original Campbell Order, confirms adequate margin. *Id*. In fact, for the fall 2025 timeframe, the auction results exceeded MISO's Reserve Margin Requirement by 2.6%. That means MISO entered the fall with more resources than necessary to ensure grid reliability. Ex. F at 19.

And as the States' Petition for Rehearing on the Original Campbell Order explains, the "elevated risk" designation that DOE cites is relatively common and has never presented an emergency before. Ex. D at 19-20. In fact, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." Ex. H at 5. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient for additional capacity if needed. Nonetheless, the Renewed Order relies on the NERC

Summer Assessment, and that "additional dispatch of the Campbell Plant is necessary," Ex. A at 2, even though the Campbell Plant was not included in any of the MISO forecasts finding sufficient capacity.

Fourth, the Renewed Order cites the PRA by cherry-picking reference to capacity offset while simultaneously acknowledging its conclusion that the results "demonstrated sufficient capacity." Ex. A at 2. Sufficient capacity, by definition, is not an emergency.

All this evidence was improperly credited when DOE issued the Original Campbell Order, and the Renewed Order compounds that error by reasserting the same flaws and mischaracterizations. This is even more troubling since the petitions challenging the Original Order placed DOE squarely on notice of the fundamental flaws in these sources. Rather than identifying and responding to an emergency, both orders together demonstrate that DOE instead started with a desired result (keeping a coal-fired plant online) and worked backwards to justify that outcome.

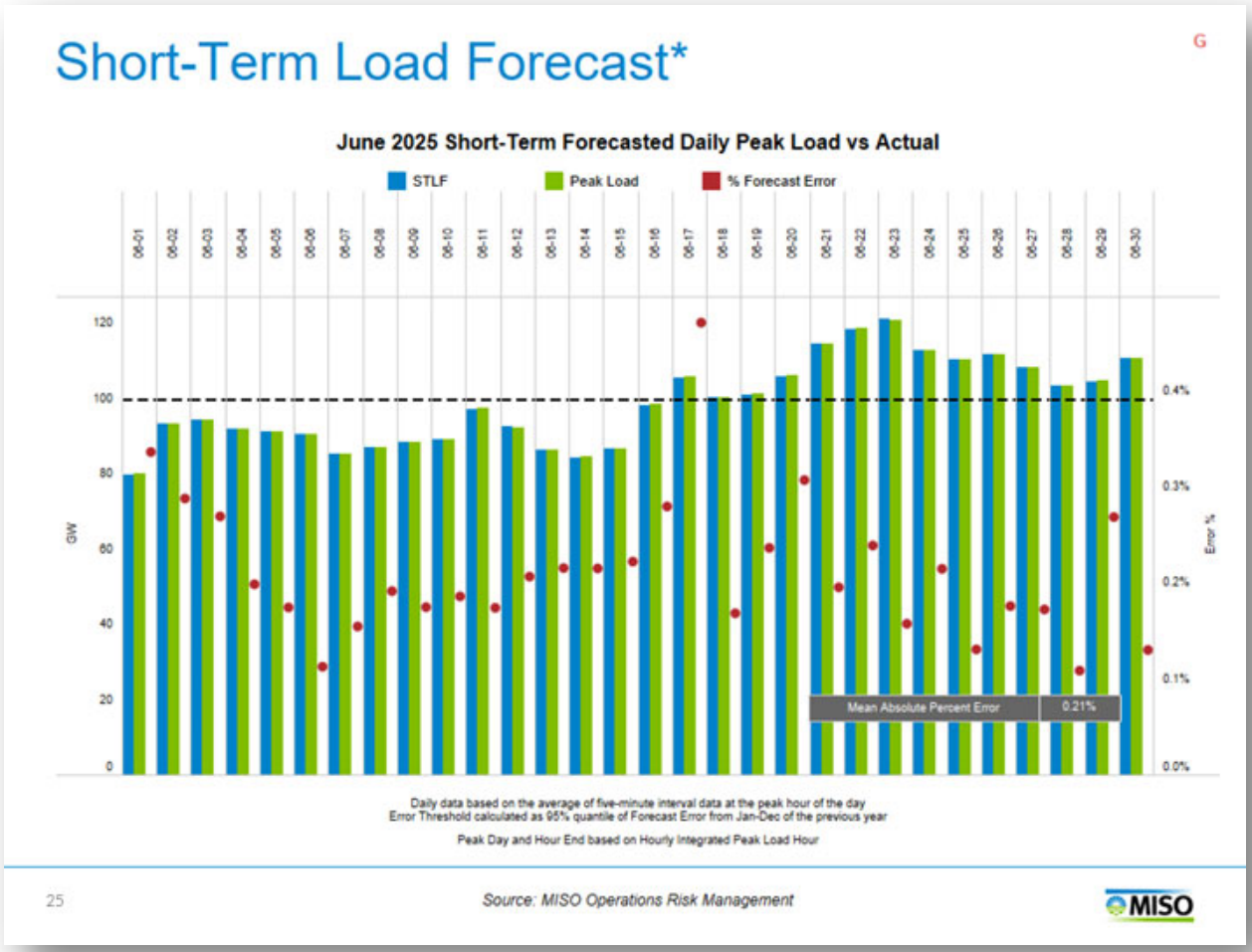
2. The additional evidence cited in the Renewed Order does not demonstrate a continuing emergency.

A continuing emergency condition does not exist, especially during the Renewed Order's applicable timeframe. After recounting the same purported evidence supplied in the Original Campbell Order, the Renewed Order then enters into a section entitled "Continuing Emergency Conditions" which presents several additional flaws, cherry-picked and out-of-context citations, and unsupported or illogical conclusions:

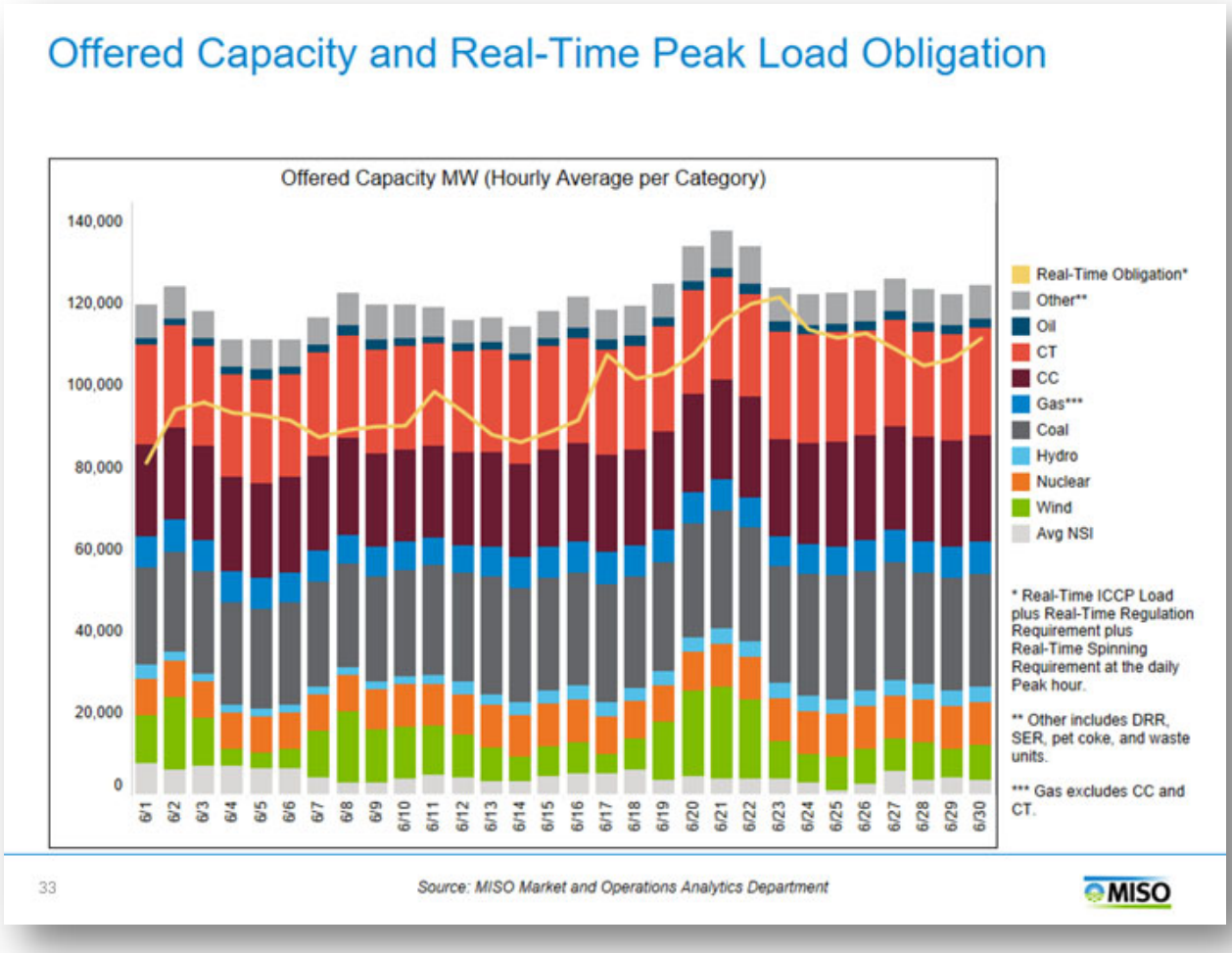
It declares that the "summer season has not yet ended" (Ex. A. at 2), but this fails to acknowledge multiple critical points. These include that peak demand is historically in June and July, not late August, that the Renewed Order was issued just days before the start of the meteorological fall, and that the Renewed Order remains in place through late November.

The Renewed Order describes how MISO called on the Campbell Plant to run in June 2025 (Ex. A at 3) without acknowledging: (1) that the Campbell Plant was only available because of the Original Order in the first place, or (2) that other resources could have supplied the capacity that the Campbell plant provided, or (3) that there was sufficient capacity within MISO even without the Campbell Plant operating, or (4) that there is no reason for DOE to conclude that the Campbell Plant's operation in June indicated any need to respond to a heat wave in September, October, or November of 2025 while the Renewed Order remains in effect.

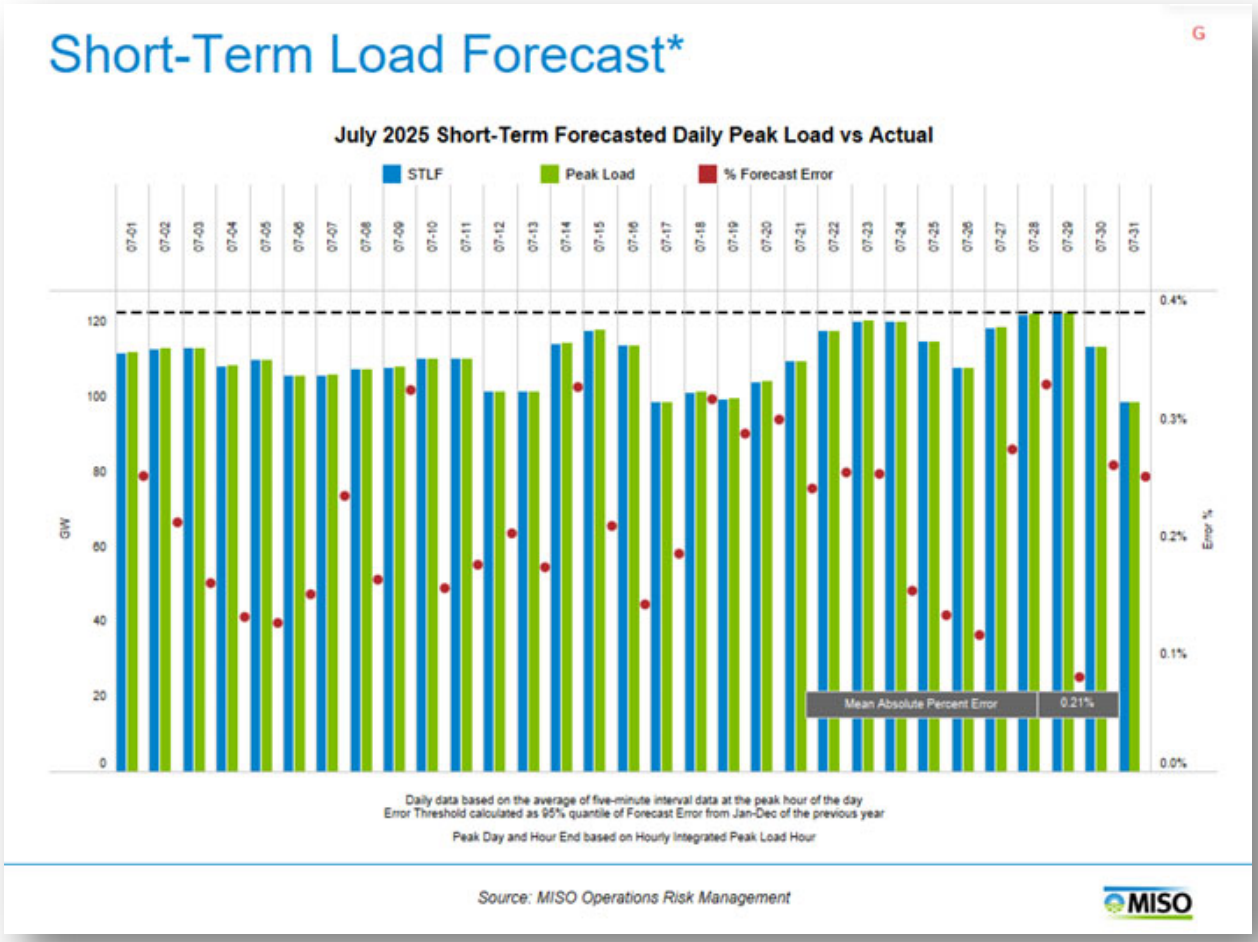
The Renewed Order attempts to justify its emergency finding by observing that MISO issued various alerts over the course of the summer (Ex. A at 3) without acknowledging: (1) that such alerts are common mechanisms for managing peak load demand every summer, and have been used for decades without any need for Section 202(c) emergency orders by DOE to keep a resource that had been slated for retirement online, or (2) that the alerts responded to summer conditions that will not be present in September, October, or November of 2025 while the Renewed Order remains in effect. Moreover, even in the peak-demand timeframe of June (Ex. M) and July (Ex. N.), when actual demand reached 120 GW on June 23, MISO had more than enough offered capacity:


Short-Term Load Forecast*
G
June 2025 Short-Term Forecasted Daily Peak Load vs Actual
STLF
Peak Load
% Forecast Error
06-01
06-02
06-03
06-04
06-05
06-06
06-07
06-08
06-09
06-10
06-11
06-12
06-13
06-14
06-15
06-16
06-17
06-18
06-19
06-20
06-21
06-22
06-23
06-24
06-25
06-26
06-27
06-28
06-29
06-30
GW
120
100
80
60
40
20
0
Error %
0.4%
0.3%
0.2%
0.1%
0.0%
Mean Absolute Percent Error
0.21%
Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour
25
Source: MISO Operations Risk Management
MISO

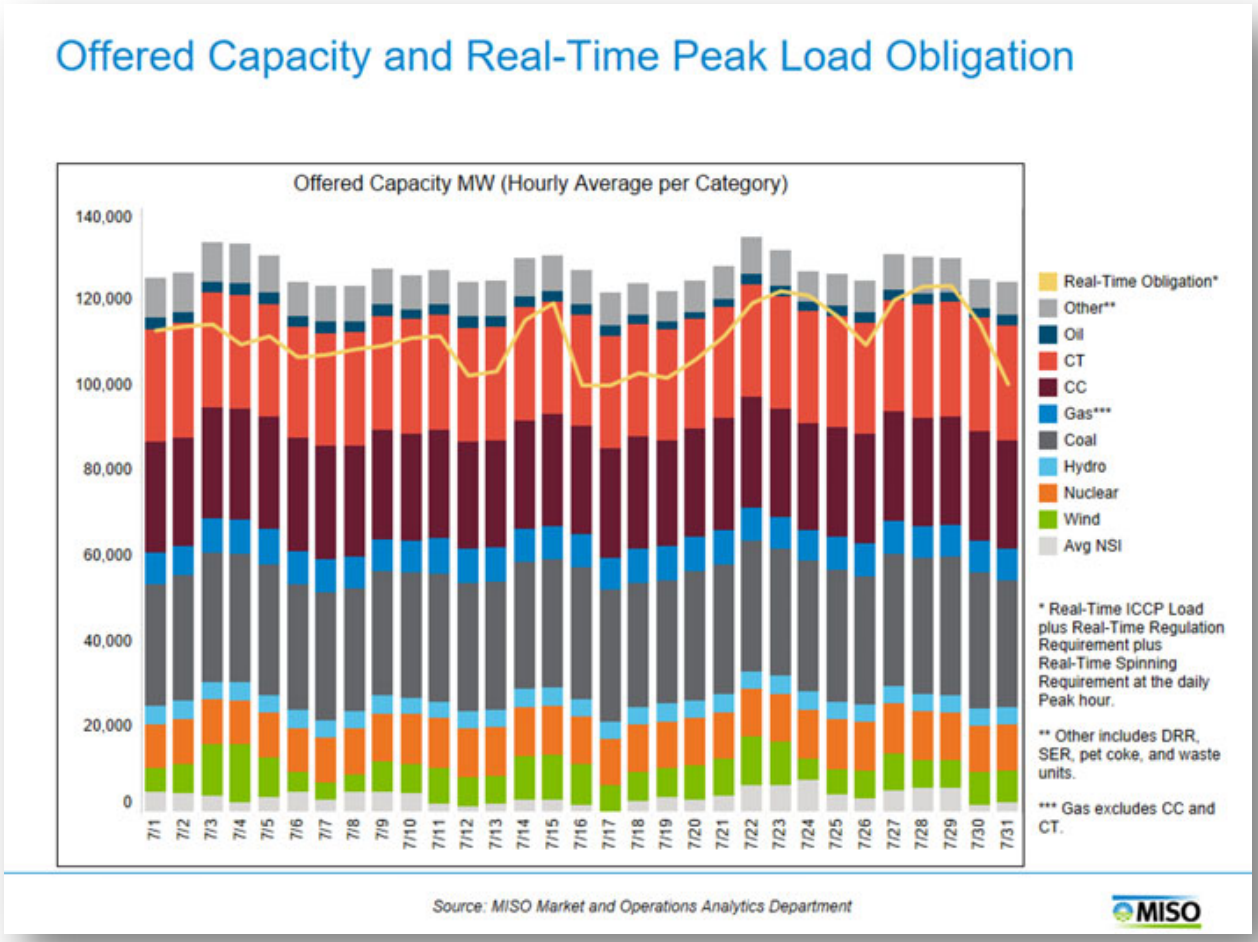
Ex. M at 25.


Offered Capacity and Real-Time Peak Load Obligation
Offered Capacity MW (Hourly Average per Category)
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
6/1 6/2 6/3 6/4 6/5 6/6 6/7 6/8 6/9 6/10 6/11 6/12 6/13 6/14 6/15 6/16 6/17 6/18 6/19 6/20 6/21 6/22 6/23 6/24 6/25 6/26 6/27 6/28 6/29 6/30
Real-Time Obligation*
Other**
Oil
CT
CC
Gas***
Coal
Hydro
Nuclear
Wind
Avg NSI
* Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the daily Peak hour.
** Other includes DRR, SER, pet coke, and waste units.
*** Gas excludes CC and CT.
33
Source: MISO Market and Operations Analytics Department
MISO

Ex. M at 33.


Short-Term Load Forecast*
July 2025 Short-Term Forecasted Daily Peak Load vs Actual
STLF
Peak Load
% Forecast Error
GW
Error %
Mean Absolute Percent Error
0.21%
Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour
Source: MISO Operations Risk Management
MISO

Ex. N at 24.



Ex. N at 32. These charts do not include more than 7000MW in headroom available to MISO beyond the offered capacity shown.[31]

The Renewed Order then cites MISO's three-year-old 2022 application to revise its resource adequacy construct to argue that the alleged "emergency" that the Renewed Order purports to address in the fall of 2025 is a year-round phenomenon. Ex. A at 3. But DOE's reliance on the application fails to acknowledge that MISO has been operating through 2025 without any

[31] *See* Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 70 at ¶¶ 16-19.

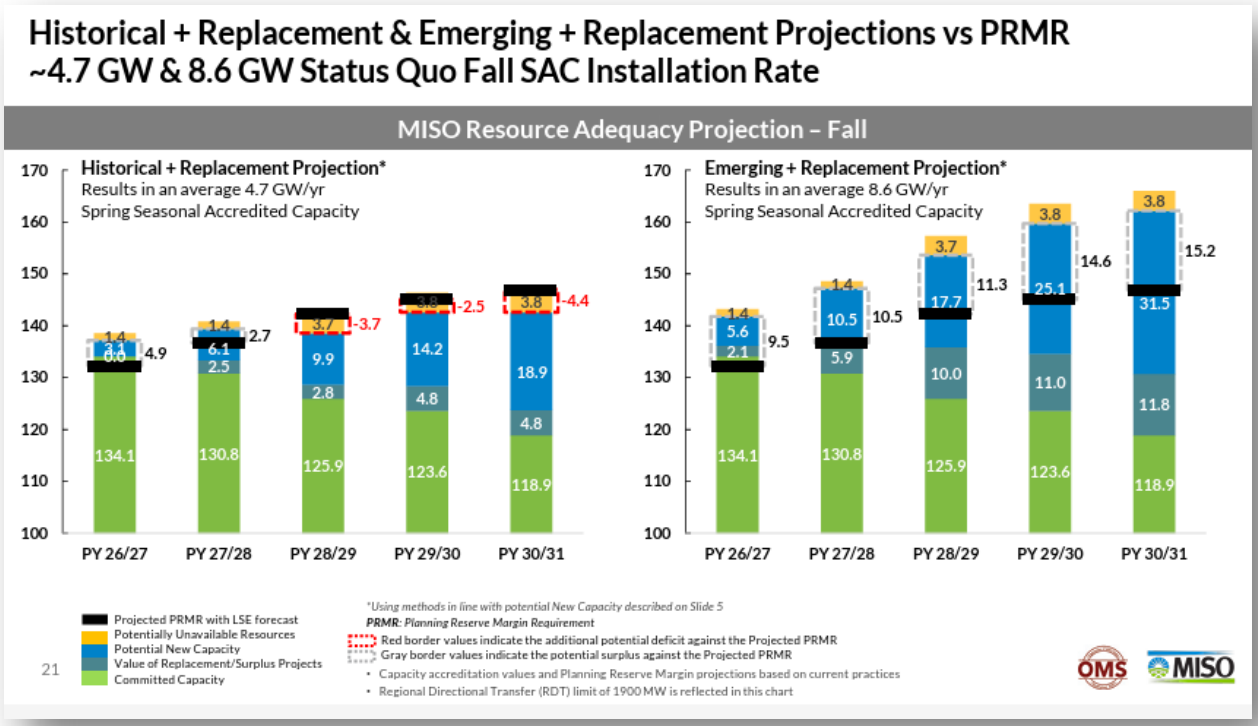
need for a Section 202(c) emergency order (other than 202-25-3) by engaging in its robust planning process that ensures adequacy and reliability.

The Renewed Order also cites MISO's 2023 Attributes Roadmap for the proposition that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. The Renewed Order does not explain how a Section 202(c) order directed to the August to November 2025 timeframe will address that eventuality several years away.

The Renewed Order also cites MISO's Response to the Reliability Imperative, concluding that MISO purportedly has "resource reliability concerns" and quotes a passage acknowledging "risks in non-summer months" that were not historically of concern. Ex. A at 4. But the Renewed Order fails to identify how generalized discussion of non-summer "concerns" and potential "risks" demonstrate any particular emergency, much less a specific one that is posed for the August to November 2025 timeframe. To the contrary, the MISO Response to the Reliability Imperative describes the risks posed by non-summer operations in the context of explaining the steps it is taking to address these risks to ensure adequate capacity and overall system reliability. Ex. O at 11. It specifically describes four pillars of approaches that MISO intends to deploy, (Ex. O at 12–24), and concludes with a "Roadmap" for how it will deploy its strategy. Ex. O at Appendix A-1. Nothing in the Renewed Order contends that these measures are inadequate or that there is an emergency despite MISO's robust efforts. *Contra* Ex. A.

The Renewed Order also cites (again) the 2025-2026 PRA results, which included a statement that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." Ex. A at 4; Ex. F at 13. Again, the actual document, in its full context, confirms adequate margin for reliability.

The Renewed Order further cites the Organization of MISO states and MISO's joint publication of a survey dated June 6, 2025. Ex. A at 4–5. But as the Renewed Order confirms, the survey confirms a surplus through the summer of 2026, well beyond the scope of the Renewed Order's timeframe. In fact, the survey shows a fall 2026 surplus using seasonally-accredited capacity against the planning reserve margin requirement:



Ex. P at 21. The Renewed Order then relies on the survey results to identify potential forecast deficits (which are not emergencies) in the 2027-2030 timeframe—but that is well outside the fall 2025 timeframe in which the Renewed Order will be in effect, and fails to account for the "Emerging + Replacement Projection" metrics throughout the document showing surpluses against the projected Planning Reserve Margin Requirement. *Id*. at 7, 9, 19–26.

The Renewed Order further cites the development of the AI industry in general, including citing the existence of 21 AI companies in Michigan. Ex. A at 6.[32] But a company's business address is not necessarily the same as where its data centers might be located, and the Renewed Order does not identify whether any of the listed companies have or intend to build data centers that would be served by the Campbell Plant's output. To the contrary, the cited article confirms that many of them have a predominance of foreign employment.[33]

The Renewed Order further cites the DOE's 2025 July 2025 Resource Adequacy Report. Ex. A at 6; Ex. Q. But that Report uses the wrong data for MISO, as the Renewal Order explicitly acknowledges. Ex. Q at 20, fn25 ("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." (emphasis added).). The Renewed Order fails to explain how data that the Report has yet to even consider can support a finding that an emergency exists in the fall of 2025.

The DOE Report also defines a shortfall, even where there is a 3%-6% operating surplus. Ex. Q at 12. And the report completely fails to apply a "perfect capacity" estimate for MISO. Ex.

---

[32] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Sep. 15, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.
[33] These include: Soothsayer Analytics: 65% of employees in India; Netlink Software Group America Inc: 65% of employees in India; Suneratech: 82% of employees in India; Ventuit: 51% of employees in India; Verdai: 100% of employees in Italy; Communication Valley Reply: 100% of employees in Italy; Altair RapidMiner: 44% in Hungary, 29% in Germany; and LENS Corporation: 100% of employees in India

Q at 20. Instead, the Report confirms that its work was done by hand with a limited number of iterations, acknowledging an incomplete analysis that explicitly should not be relied upon. *Id.* at 19 ("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." (emphasis added)). Yet the Renewed Order relies upon it.

The Renewed Order further cites testimony by MISO's Senior Vice President of Planning and Operations, Jennifer Curran. Ex. A at 6. But the Renewed Order (apparently intentionally) omits a critical sentence from the passage it cites, which provides important context: "A growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them. This can be addressed by letting local reliability requirements determine the pace of retirement of existing power plants." Ex. R at 7 (emphasis added). Further testimony undermines the very proposition for which the Renewed Order purports to rely on Ms. Curran's testimony. She also repeatedly confirmed that resource planning is the purview of individual states and utilities in the MISO region, which can be used to mitigate the risk:

- "More work remains to be done… Let reliability needs help inform the pace of retirement of existing electric generating resources, ensuring they aren't retired before adequate new electric generation is available." Ex. R. at 2.
- "The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet needed load for their area and states having jurisdiction over electric resource adequacy decisions." Ex. R at 4.

- "Two of our most important tools are the Futures Planning Scenarios, which are MISO projections capturing a range of potential system conditions over a 20-year horizon, and the annual Organization of MISO States and MISO survey, a voluntary survey of generation owners to assess available resource capacity to serve the projected load over the next five years. These regularly updated studies provide the basis for long-term transmission planning efforts and help inform the electric resource planning decisions, which are the purview of the states and utilities in the MISO region." Ex. R at 6.

In total, none of this evidence demonstrates that there is any emergency, much less one that might occur in the August 20 to November 19 timeframe. To be sure, there are normal capacity considerations including some that pose some degree of potential risk, but not one of the sources cited in the Renewed Order evidences any lack of adequate planning to address those risks, much less any likelihood of a shortfall between August 20 and November 19, 2025.

Instead, the robust and comprehensive planning processes undertaken by the prime authorities—the individual states, the utilities, and MISO—have comprehensively planned for resource adequacy and system reliability during the fall 2025 and beyond.

Given all these countervailing considerations, and the full context of the sources that DOE purports to cite, DOE did not have substantial evidence supporting its emergency determination. It did not exercise reasoned decision-making in declaring that an emergency exists. Its Renewed Order is arbitrary and capricious.

B. The Renewed Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371.

DOE exceeds its authority because the Renewed Order does not address any actual emergency or sudden occurrence needing imminent response, and because it has not identified any

actual and specific insufficient supply situation, for the August 20 to November 19 timeframe. Thus the Renewed Order is without authority and contrary to law.

As the statutes make clear, an actual "emergency" is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c). And Department regulations define "emergency" to mean 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." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1

& 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[34]

Past practice further confirms the impropriety of the Renewed Order. While DOE's emergency powers have occasionally been used to address retirements like the Campbell Plant, it has done so only when requested by the operator or local government and there was a specific need demonstrated for the units to operate due to an unexpected emergency. DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant to supply Washington D.C. when transmission lines were out of service); DOE Order No. 202-17-1 at 2 (Grand River Energy to operate Unit 1 due to lighting strike to Unit 2 and delay in construction for Unit 3); DOE Order No. 202-17-2 (need to operate Yorktown to avoid imminent risk of load-shedding).

A memorandum by the Congressional Research Service, Ex. S, confirms that DOE's use of Section 202(c) to order a plant to be generally available is novel. Ex. S at 3 (Department engaging in "seemingly new interpretations of the emergency authority").

Indeed, the statutory structure of the Federal Power Act confirms the short-term nature of emergency approaches. That is because long-term planning authority appears in an entirely different Section of the Federal Power Act – Section 215—which indicates that the emergency authority of Section 202(c) is a different authority altogether. 16 U.S.C. § 824o. Given all the procedures attendant to resource planning, this statutory structure confirms that emergency orders are not the proper mechanism to engage in resource planning five years into the future. *See FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 142, 149 (2000); s*ee also Cal.*

---

[34] MISO, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023) ("*Winter Storm Elliott Overview*") at 7, available at https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

Indep. Sys. Operator Corp. v. FERC, 372 F.3d 395, 401–02 (D.C. Cir. 2004) (DOE's authority in one Section of the Federal Power Act "is strong evidence" that a separate Section does not confer the same authority on the agency).

Courts have also recognized Section 202(c)'s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply." 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm'n*., the Eighth Circuit noted that 202(c) provides authority to "react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency." 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that a separate provision, section 202(b) [35] applies to the former, while section 202(c) applies to the latter:

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

[35] Section 202(b) refers to 16 U.S.C. § 824a(b), which states "[w]henever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility" if the utility would not face an undue burden. The DOE's authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

Id. at 234. In that case, a power company challenged the FPC's order issued under § 202(b) of a temporary connection between the power company and a small municipally owned power producer that was "dangerously close to eroding its firm power supply" due to the proximity between the generator load capacities and the peak load demand. *Id.* It claimed that because the ordered connection was temporary, the order could only be issued under section 202(c), and only in emergency conditions. *Id.* The court disagreed that section 202(c) only applies to temporary orders but agreed that a potential crisis in the foreseeable future was not an emergency, making it "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)." *Id.* The caselaw is therefore clear: for DOE to have any authority under section 202(c) the emergency must be actual and not merely a broadly asserted projected risk.

Statutory text and structure, past practice, and caselaw are therefore all clear: for DOE to have any authority under section 202(c), the emergency must be actual and not merely a broadly asserted projected risk. With no such actual or even imminent emergency, the Renewed Order is unlawful.

C. The Renewed Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1).

The Renewed Order also is unlawful because it purports to require actions not within DOE's statutory authority.

DOE's authority is limited to issuing orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant <u>availability</u> untethered to meeting any specific need, nor does it allow for <u>potential</u> economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur and specifically does not allow for the Department

to order availability without a specific need to be available.[36] Plus, "economic dispatch" is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean only the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO's determination of lowest-cost sources may not result in the Campbell Plant producing *any* generation whatsoever during the fall of 2025. (Or if it does, it could be as a result of the Original Campbell Order or the Renewed Order being in place rather than an external need.) Thus, the DOE is without authority, and the Renewed Order is contrary to law.

D. The Renewed Order exceeds DOE's authority because it does not set hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3).

The order must be limited to only those hours necessary to meet the emergency. 16 U.S.C. § 824a(c)(2).

The Renewed Order addresses only the potential for an emergency, but it does not identify a need for the Campbell Plant to generate electricity to meet it. By the same token, the Renewed Order does not establish any limited hours or other parameters for the Campbell Plant to follow to ensure it meets the purported emergency, only that it always be available. Thus, the DOE is without authority, and the Renewed Order is contrary to law, because it allows the Campbell Plant to generate electricity during times there are not even "elevated risks." Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the

[36] Before the Original Campbell Order, of the 19 times the DOE has issued a 202(c)(1) Order, only once, for Mirant in 2005, did it require a plant to supply as-needed additional capacity—but even then, it was based on a specific application demonstrating a concrete and specific need. DOE Order No. 202-05-3 (Dec. 20, 2005). That is not the case here.

environmental impacts that, by law, the Renewed Order must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus, the DOE is without authority, and THE Renewed Order is contrary to law.

E. The Renewed Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states.

Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). Decisions over what plants should be constructed or retired are traditionally subject to state regulation. States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). "The states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy" *Coal. for Competitive Elec., Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2d Cir. 2018). What facilities to build, whether they remain feasible, and utility rates are areas governed by the states. *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

The energy market is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the Federal Power Act—which explicitly declares that FERC may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission." 16 U.S.C. § 824h(b). Indeed, FERC has embraced these cooperative federalism principles and developed long-standing consultation practices with the states, including through creation of a Joint Federal-State Task Force. Ex. T. And more recently, a Federal-State Current Issues Collaborative. Ex. U.

Section 103 of the Department of Energy Organization Act, also applicable, mandates due consideration to state retirement plans and requires, where practicable, consultation with relevant state officials. 42 U.S.C. § 7113.

States are responsible for developing and approving power generation plans, typically through public commissions like the Minnesota Public Utilities Commission[37] and the Wisconsin Public Service Commission.[38] These bodies oversee the development of Integrated Resource Plans ("IRPs"), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota's IRP statute). An IRP can consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.[39] Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.[40]

MISO, in turn, is one of the country's largest RTO, which was formed to develop transmission systems, trading markets, and attendant procedures.[41] MISO works collaboratively

---

[37] Minnesota Public Utilities Commission, *Utility Planning*, https://mn.gov/puc/activities/economic-analysis/planning/ (last visited June 23, 2025).
[38] Wis. Stat. Ann. § 196.491 (West).
[39] *Id*.
[40] Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last visited June 23, 2025).
[41] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf

with its member states to ensure resource adequacy throughout its service area.[42] This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[43] MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And MISO then accounts for the final IRPs in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.[44] MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual PRA, which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.[45]

The Campbell Plant's planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to MCL 460.6t & for Other Relief.*, No. U-21090, 2022 WL

---

[42] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).
[43] *Id*.
[44] *Id*.
[45] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

2915368, at *73 (June 23, 2022). The Michigan Public Services Commission approved Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id*. at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v. Mich. Pub. Surv. Comm'n (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether retirement will pose any concern for grid reliability. [46]

Consumers Energy submitted Attachment Y form to MISO on December 14, 2021, providing notice that it planned to suspend generation at the Campbell Plant by June 1, 2025. MISO approved the Campbell Plant's retirement on March 11, 2022. In making its approval, MISO determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria."

DOE did not adequately consult with the state, much less account for or incorporate the findings of MISO when it approved Consumer's Energy's Attachment Y submission. Michigan state regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in their states including the Campbell Plant. *Zibelman*, 906 F.3d at 50. DOE's failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory

[46] If MISO does identify a threat to grid reliability if the resource retires, the MISO tariff provides a mechanism to retain that resource until the constraint can be alleviated.

reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of the Federal Power Act regarding federal-state collaboration and upends FERC's historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely "practicable" here given the lack of an imminent emergency. The Renewed Order did not give any consideration (much less due consideration) to Michigan's IRP, in violation of law. 42 U.S.C. § 7113.

In the Renewed Order's focus on longer-term risks, including the growth of data centers and the projections out into the 2027-2030 timeframe, DOE is improperly inserting itself into long-term resource planning, usurping a role belonging to the respective states. The DOE cannot use short-term emergency orders to serve a purpose for which DOE's emergency authority was not designed: to supplant the states' primary authority in the long-term resource planning arena.

The Order usurps the State of Michigan's primary rule in resource planning and development; it is contrary to law.

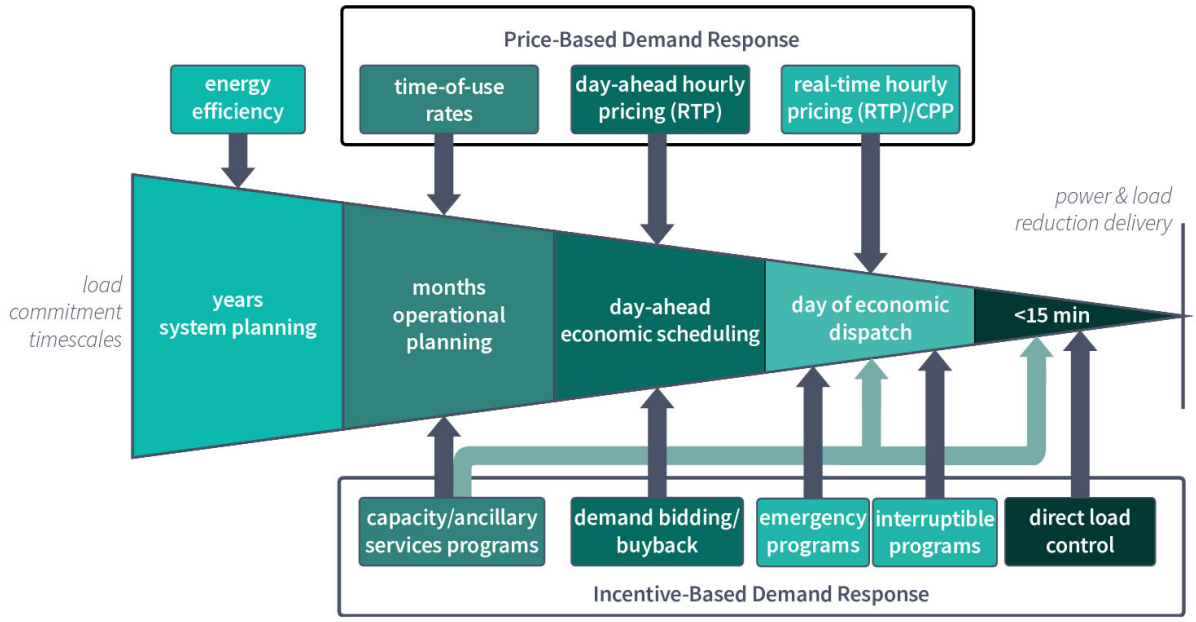
F. The Renewed Order is unreasoned, arbitrary, and capricious because its directive for "economic dispatch" is inherently contradictory with the needs to meet an actual emergency.

Section 202(c) contemplates emergency orders that are tailored to the specific emergency—they must "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). Even if an emergency did exist and DOE had the legal authority to issue an order, this Renewed Order is not rationally related to addressing the emergency that the order identifies.

The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant undermines its determination that an emergency exists and cannot "best meet" the purported emergency. Economic dispatch is a term of art for the procedure by which

MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. "Economic dispatch," by definition, is awarded to the lowest-cost option (all else being equal). Ex. V. That is because much of the base load planning takes place years or months ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations



Source: U.S. Department of Energy[82]

Ex. V at 43. Most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Ex. W at 6–7, 13, 51. As recently as 2021, the vast

majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal. See Ex. X at 2.

Taken together, economic dispatch considers a variety of factors including (1) the cost of generation, (2) the standby condition of the generator, (3) ramp-up time to provide the needed capacity, and (4) whether electric energy can be transmitted to the area of need.

The Renewed Order's proposed solution for "economic dispatch" of the Campbell Plant is thus inherently incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, even uneconomic plants receive cost-of-service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a "price taker" using MISO's "must run" classification. Thus, the Order's directive to use "economic dispatch" is irrational: actual emergencies are not addressed with economic dispatch, and economic dispatch is a necessarily ineffective method to address an actual emergency.[47]

Moreover, the Renewed Order's requirement that the Campbell Plant be "available to operate" does not accord with 202(c)(1)'s requirement that DOE select the temporary measure that will "best meet the emergency and serve the public interest." Section 202(c)(1)'s use of the term "best" shows that the Commission cannot require temporary power generation from the Campbell Plant when better means are available to meet the alleged emergency and serve the public interest.

---

[47] Campbell's situation illustrates this inefficiency. Coal is an expensive fuel type in our current energy mix. The inefficiency of running a coal plant makes it uneconomic in general, which is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

Entergy Corp. v. Riverkeeper, Inc., 556 U.S. 208, 218 (2009) ("Best" means what is "most advantageous." (Quoting Webster's New International Dictionary 258 (2d ed.1953))). DOE's decision to require the Campbell Plant to be available disregarded its obligation to consider alternatives and select the best one.

Although DOE need not consider every conceivable alternative, it must consider those that are obvious and viable. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020); *Motor Vehicle Manufs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g.*, *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (evaluating agency failure to consider alternative raised by dissenting Commissioners and introduced by commenters); *cf.* 10 C.F.R. § 205.370 (stating ability to cancel, modify, or otherwise change an order). Indeed, DOE's regulations specify information it shall consider when deciding to issue an order under section 202(c). 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." *Id*. § 205.373(g)–(h); Ex. Y at 4 (DOE Order No. 202-22-4). DOE has not explained why ordering the Campbell Plant to remain "available" meets any of these criteria, especially considering alternatives such as power pooling and utility coordination.

DOE has not explained why its Renewed Order "best" meets the emergency, because it does not. Again, the Renewed Order alleges only that the Campbell Plant should remain available

because a need *might* arise in the future (and even then, most likely years from now, not in the August to November timeframe). Given the speculative nature of the alleged emergency, it is incorrect as a matter of fact that ordering the Campbell Plant to remain available is the best means of addressing it. DOE's failure to consider alternatives other than the inefficient and incapable Campbell Plant does not meet section 202(c) requirement for DOE to use its judgment to choose the best temporary source of emergency energy.

First, if an emergency need occurs in the day-of or real-time markets, the Campbell Plant will not be able to spool up in time to meet that need. That is because it takes over 12 hours to reach peak load. Ex. Z.[48]

Second, even if there was adequate notice for the Campbell Plant to deliver energy in an emergency, its age and unreliability make it a poor choice to rely on for emergency services.[49] The Campbell Plant's unreliability was one of the reasons it was slated for retirement. In 2023 and 2024, Campbell experienced long, recurring outages that demonstrated it should not be relied on as an emergency power source. For example, in 2023, Unit 2 experienced four outages totaling 3,445 hours—nearly 40 percent of the year—due to a pump failure, and in 2024, Unit 3 experienced an outage totaling 1,104 hours due to a failure in one of the turbine's gears.[50] Even during the June 23, 2025, peak load event during the heat wave, Campbell did not run two of its three units. *Id*.

---

[48] Adapted from U.S. Energy Information Administration submissions according to Forms EIA-860 and EIA923, in which "OVER" indicates ramp-up time exceeding 12 hours. *See* https://www.eia.gov/electricity/data/eia860/; https://www.eia.gov/electricity/data/eia923/.
[49] *See* Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibits 103-104.
[50] *Id*. Exhibit 3.

Even if there was adequate transmission and lead time, the Campbell Plant's expensive fuel source means that its bid to provide electricity would be higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), which would prevent it from being selected as the most economic resource to meet the need. Again, even during the peak load in June of 2025, only one of the Campbell Plant's units was online, and it produced only 761MW of power. Ex. AA.[51] That represents a small fraction of the remaining margin that MISO had available and demonstrates that the Campbell Plant is not an efficient means of meeting an emergency energy demand.

Finally, if, for example, there was a need for additional electricity in North Dakota in October of 2025, it is unlikely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Campbell Plant to meet that need.

Rather than ordering the Campbell Plant to remain available, DOE was required to consider obvious alternatives that MISO has available and uses as part of its role as a regional transmission grid operator. The Department has long recognized that power pools and utility coordination "are a basic element in resolving electric energy shortages." *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981). And recent history bears out the important role of transmission connectivity along with imports and exports.[52] The fact that DOE has intruded on

---

[51] *Sourced from* https://campd.epa.gov/data/custom-data-download.

[52] *See, e.g.*, Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 43 at § III.A.3.b (Winter Storm Elliott System Operations Inquiry) ("Despite tightening conditions on the MISO system . . . MISO maintained steadily increasing exports to TVA throughout the day."); Exhibit 44 at 43 (PJM Elliott Report) (describing PJM exports of between 8 and 11 GW to TVA and other neighboring regions), 83–84 (describing PJM power exports to MISO and graphically depicting those exports over time); Exhibit 36 at 6 (MISO Elliott Max. Gen. Event Overview) ("MISO consistently exported power to southern

MISO's role of planning for and meeting fluctuations in demand without considering these viable and obvious alternatives shows that it did not comply with section 202(c).

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Renewed Order improperly imposes measures that are not tailored to anything. All the while, the Order imposes costs on the States to bring the Campbell Plant to operational status beyond its planned retirement, adds potentially expensive generation to the mix if it were to run in the August 20-November 19 timeframe, and generates harmful pollution at the same time. Thus, the Renewed Order requiring the Campbell Plant to remain available and for MISO to take steps to use the Campbell Plant for economic dispatch is irrational and arbitrary where the Campbell Plant is unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need it is supposed to meet in the first place.

Therefore, the Renewed Order is not rationally related to meeting the need of the purported emergency that it identifies.

G. The purported emergency is pretext for a prejudged outcome.

The Renewed Order is not a good faith effort to carry out DOE's duties under the Federal Power Act. Rather, the materials supporting the Renewed Order demonstrate a pretextual effort to further the administration's policy support for fossil fuels, and in particular coal electricity generation.

Where the conduct of the agency shows an "unalterably closed mind on matters critical to the disposition of th[is] proceeding," it requires either disqualification of the administrator or

---

neighbors with a maximum value of nearly 5 GW."); *and* Exhibit 7 at 1 (DOE Order No. 202-02-1) (providing for usage of interregional transmission).

withdrawal of the proposal. *Ass'n of Nat'l Advertisers v. FTC*, 627 F.2d 1151, 1170 (D.C. Cir. 1979); *Nehemiah Corp. of Am. v. Jackson*, 546 F.Supp. 2d 830, 847 (E.D. Cal. 2008) (describing the appropriate remedies when an agency official has prejudged the outcome of a particular matter). A preexisting internal directive to reach a particular result is strong evidence that the official is not "free, both in theory and in reality, to change his mind" in the agency proceedings. *Nat'l Advertisers*, 627 F.2d at 1172; *see Int'l Snowmobile Mfrs. Ass'n v. Norton*, 340 F. Supp. 2d 1249, 1260 (D. Wyo. 2004).

The Renewed Order cites a bevy of Executive Orders declaring an energy emergency. Even if these Executive Orders are taken at face value, they are incoherent with the President's other actions to reduce capacity of new energy generation, such as from ongoing and nearly-completed wind projects. *Temporary Withdrawal of All Areas on the Outer Continental Shelf From Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects* 90 Fed. Reg. 8,363 (Jan. 20, 2025); *Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources*, 90 Fed. Reg. 30,821 (Jul. 10, 2025).

Further, the administration has declared a preference for coal energy. *Executive Order 14261: Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15,517 (Apr. 8, 2025). The express mandate of Executive Order 14261 declared it to be the national policy "to support the domestic coal industry by removing Federal regulatory barriers that undermine coal production, encouraging the utilization of coal to meet growing domestic energy demands, increasing American coal exports, and ensuring that Federal policy does not discriminate against coal production or coal-fired electricity generation."

But this was not a simple policy preference—the administration had already predetermined that it would resort to emergency authority to reopen or forestall closure of coal plants before it

ever issued the Original Campbell Order or the Renewed Order. On April 8, 2025, President Trump gave remarks during the signing ceremony for Executive Order 14261. In those remarks, he noted that the administration would take action to reopen coal plants.[53] Also on April 8, 2025, the Department of Energy announced several initiatives directed to increasing coal production.[54]

During a Bloomberg TV interview in February 2025, Secretary Wright declared that the United States should stop the closure of coal power plants, and asserted that DOE had the authority to do so.[55]

On July 7, 2025, Secretary Wright was quoted as saying, "I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those."[56]

On July 11, 2025, the DOE posted a video Secretary Wright to the department's social media accounts with the chyron, "BIG BEAUTIFUL CLEAN COAL. This is the largest source of global electricity and third largest source of electricity in the U.S."[57]

The DOE's social media feeds are full of clips from Secretary Wright media appearances extoling coal plants, promising to increase the use of coal for energy production, and asserting that DOE had the authority to forestall closures.

---

[53] https://www.presidency.ucsb.edu/documents/remarks-domestic-coal-production ("And all those plants that have been closed are going to be opened if they're modern enough." And "From now on, we'll ensure that our Nation's critically needed coal plants, as an example, remain online and fully operational. They're always going to be operational.")
[54] https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing
[55] https://www.bloomberg.com/news/articles/2025-02-11/us-should-stop-closure-of-coal-fired-power-plants-wright-says.
[56] https://www.wvnews.com/statejournal/news/top_story/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_4ffcdad0-9030-4e6f-8ca7-0816e1786cbc.html
[57] *E.g.*, https://www.facebook.com/energy/videos/big-beautiful-clean-coal-this-is-the-largest-source-of-global-electricity-and-th/1468968367585884/.

The administration, and DOE in particular, engaged in prejudgment of the Renewed Order. Knowing that it needed to effectuate the administration's policy preference to keep coal plants open, DOE worked backwards from that preferred result and justified it using post-hoc rationalizations. Secretary Wright demonstrated an "unalterably closed mind on matters critical to the disposition" of the use of emergency authority, requiring the Renewed Order to be set aside. *Nat'l Advertisers*, 627 F.2d at 1170; *Nehemiah Corp.*, 546 F. Supp. 2d at 847.

CONCLUSION

For all of the foregoing reasons, the Department should rescind the Renewed Order.

KEITH ELLISON
ATTORNEY GENERAL
OF MINNESOTA

/s/ Peter Surdo
Peter Surdo
Cat Rios-Keating
Alyssa Bixby-Lawson
Special Assistant Attorneys General
Office of the Minnesota Attorney General
445 Minnesota St., Suite 600
St. Paul, MN 55101

Dated: September 19, 2025

KWAME RAOUL
ATTORNEY GENERAL OF
THE STATE OF ILLINOIS

/s/ *Samuel C. Lukens*
Samuel C. Lukens, Assistant Attorney General
Susan L. Satter, Chief, Public Utilities Bureau
Jason E. James, Assistant Attorney General
Office of the Illinois Attorney General
115 South LaSalle, 25th Floor
Chicago, Illinois 60603

Dated: September 19, 2025

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-9

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and apply for rehearing of the Department of Energy's ("DOE") November 18, 2025, Order No. 202-25-9 ("Campbell Order III," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." The Campbell III Order is in effect from 00:00 Eastern Standard Time ("EST") on November 19, 2025, and expires at 00:00 EST on February 17, 2026.[2] This is the third in a series of orders directing MISO to take the same actions for the same facility and based on the same alleged statutory authority and factual circumstances.

The States have an interest in and are aggrieved by Campbell Order III. *FDA v. R.J. Reynolds Vapor Co.*, 606 U.S. 226, 232–36 (2025) (defining an "adversely affected or aggrieved"

[1] All Exhibits are lettered and attached.
[2] This petition is being submitted to DOE's AskCR <askcr@hq.doe.gov> account as DOE instructs.

party within the APA as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

The Campbell III Order continues the pattern established by two prior DOE Orders numbered 202-25-3 ("Campbell I") and 202-25-7 ("Campbell II") that also directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date of June 1, 2025, through November 18, 2025.

The States requested rehearing of the Campbell I and II Orders and described the applicable facts, with record support, in those challenges. Exs. B-C (nested exhibits omitted). Campbell III is almost identical to Campbell II, which in turn extended Campbell I. Because the legal and factual issues here directly overlap and repeat the same matters previously raised, the States hereby incorporate by reference the petitions for rehearing of the Campbell I and II Orders, including all arguments, exhibits, and other referenced materials, and reassert them as grounds for rehearing of the Campbell III Order.

The States will be adversely affected by the Campbell III Order in the same ways they were harmed by the Campbell I and II Orders, but Campbell III also compounds and increases those harms through ongoing, cumulative emissions and related impacts. The negative effects on the States were described in the prior challenges and are hereby incorporated by reference.[3]

[3] The harms include economic harm to ratepayers in the States who are saddled with the increased costs associated with operating the inefficient, coal-burning Campbell Plant, the environmental harms of operating the coal plant, and the harm caused by usurping the States' role in planning resource adequacy and generation.

The Campbell III Order compounds the errors of the prior orders for all of the reasons set forth in the States' Petitions for Rehearing filed June 23, 2025 (Campbell I) and September 19, 2025 (Campbell II).

As with the Campbell I and II Orders, the Campbell III Order should be rescinded because it lacked reasoned decisionmaking, exceeded DOE's authority, was not rationally tailored to meet the purported emergency, and demonstrated impermissible prejudgment of the relevant issues.

In addition to the grounds laid out in the requests for rehearing on the Campbell I and II Orders, Consumers Energy Company filed its most recent 10-Q and 8-K reports with the Securities and Exchange Commission on October 30, 2025. Consumers Energy reported that for the period from May 23, 2025 through September 30, 2025, the costs of keeping Campbell online were $164 million, but the plant made only $84 million in revenue from the sale of its output, netting an $80 million loss. Exs. D (summary of contents), E (copy of 10-Q). Specifically,

> During the initial emergency order period, the net financial impact of compliance was $53 million after applying MISO revenues of $67 million. For the second emergency order period through September 30, 2025, the net financial impact of compliance was $27 million after applying MISO revenues of $17 million.

Ex. E. at 62. Consumers Energy concluded that it would seek to recover the $80 million in net losses from ratepayers through FERC tariff proceedings. *Id*. These real-world figures confirm that the plant cannot be effectively used for "economic dispatch" because it is uneconomical and runs at a loss when operated as the Campbell III Order requires. They also confirm that operating Campell plant as ordered has not and will not "minimize cost to ratepayers" where net losses will be charged to them. Thus, the Consumers Energy SEC filings demonstrate that the Campbell III Order cannot be fulfilled according to its own terms. Ex. A at 8.

In addition to the Exhibits (A through E) attached to this request for rehearing, DOE is already in possession of the exhibits the States submitted in support of their petitions for rehearing of the Campbell I and II Orders. The States are not resubmitting those same documents since they are incorporated by reference into the record for this petition. If DOE needs additional copies of any documents, please contact any of the signatories to this request.

KEITH ELLISON
ATTORNEY GENERAL
OF MINNESOTA

/s/ Peter Surdo
Peter Surdo
Cat Rios-Keating
Alyssa Bixby-Lawson
Special Assistant Attorneys General
Office of the Minnesota Attorney General
445 Minnesota St., Suite 600
St. Paul, MN 55101

Dated: December 18, 2025

KWAME RAOUL
ATTORNEY GENERAL OF
THE STATE OF ILLINOIS

/s/ *Samuel C. Lukens*
Samuel C. Lukens, Assistant Attorney General
Susan L. Satter, Chief, Public Utilities Bureau
Jason E. James, Assistant Attorney General
Office of the Illinois Attorney General
115 South LaSalle, 25th Floor
Chicago, Illinois 60603

Dated: December 18, 2025

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-26-16

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and apply for rehearing of the Department of Energy's ("DOE") February 17, 2026, Order No. 202-26-16 ("Campbell Order IV," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." The Campbell IV Order is in effect from February 17, 2026, until May 18, 2026.[2] This is the fourth in a series of orders directing MISO to take the same actions for the same facility and based on the same alleged statutory authority and factual circumstances.

The States have an interest in and are aggrieved by Campbell Order IV. *FDA v. R.J. Reynolds Vapor Co.*, 606 U.S. 226, 232–36 (2025) (defining an "adversely affected or aggrieved" party within the APA as "anyone even 'arguably within the zone of interests to be protected or

[1] All Exhibits are lettered and attached.
[2] This petition is being submitted to DOE's AskCR <askcr@hq.doe.gov> account as DOE instructs.

regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

The Campbell IV Order continues the pattern established by three prior DOE Orders numbered 202-25-3 ("Campbell I"), 202-25-7 ("Campbell II"), 202-25-9 ("Campbell III") that also directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date of June 1, 2025, through February 17, 2026.

The States requested rehearing of the Campbell I, II, and III Orders and described the applicable facts, with record support, in those challenges. Exs. B–D (nested exhibits omitted). Campbell IV is almost identical to Campbell III, which extended Campbell II, which in turn extended Campbell I. Because the legal and factual issues here directly overlap and repeat the same matters previously raised, the States hereby incorporate by reference the petitions for rehearing of the Campbell I, II, and III Orders, including all arguments, exhibits, and other referenced materials, and reassert them as grounds for rehearing of the Campbell IV Order.

The States will be adversely affected by the Campbell IV Order in the same ways they were harmed by the Campbell I, II, and III Orders, but Campbell IV also compounds and increases those harms through ongoing, cumulative emissions and related impacts. The negative effects on the States were described in the prior challenges and are hereby incorporated by reference.[3]

[3] The harms include economic harm to ratepayers in the States who are saddled with the increased costs associated with operating the inefficient, coal-burning Campbell Plant, the environmental harms of operating the coal plant, and the harm caused by usurping the States' role in planning resource adequacy and generation.

The Campbell IV Order compounds the errors of the prior orders for all of the reasons set forth in the States' Petitions for Rehearing filed June 23, 2025 (Campbell I), September 19, 2025 (Campbell II), and December (Campbell III).

As with the Campbell I, II, and III Orders, the Campbell IV Order should be rescinded because it lacked reasoned decisionmaking, exceeded DOE's authority, was not rationally tailored to meet the purported emergency, and demonstrated impermissible prejudgment of the relevant issues.

In addition to the grounds laid out in the requests for rehearing on the Campbell I, II, and III Orders, Consumers Energy Company filed its most recent 10-K report with the Securities and Exchange Commission on February 10, 2026. Ex. E. Consumers Energy reported:

> In January 2026, Consumers filed a request at FERC seeking recovery of the net financial impact of complying with the May 2025 emergency order, which was $42 million after applying MISO revenues of $78 million. This filing encompasses recovery sought by the joint owners of J.H. Campbell.
>
> For the second emergency order period through December 31, 2025, the net financial impact of compliance was $93 million after applying MISO revenues of $77 million. Consumers will seek recovery of these compliance costs at a later date, consistent with rate recovery sought for the May 2025 emergency order. The ultimate financial impact remains subject to the outcome of the FERC proceeding and any future guidance or interpretation.

Ex. E at 117–18. In total, DOE's orders in Campbell I and Campbell II cost ratepayers in MISO a total of $135 million. These real-world figures confirm that the plant cannot be effectively used for "economic dispatch" because it is uneconomical and runs at a loss when operated as the Campbell Orders I–IV require. They also confirm that operating Campell plant as ordered has not and will not "minimize cost to ratepayers" where net losses will be charged to them. Thus, the Consumers Energy SEC filings demonstrate that the Campbell III Order cannot be fulfilled according to its own terms. Ex. A at 10.

Finally, although the Campbell IV order purports to rely on emergency weather alerts related to Winter Storm Fern, the States' prior submissions have already put DOE on notice that such alerts are of limited value for supporting an emergency declaration. *See* Ex. C at 27. That is because alerts are commonplace, have been used for decades, and have never before required declaring a Section 202(c) emergency. The purpose of the alerts is to put system-wide resources on notice that they may be needed. They do not indicate an emergency that would require invoking Section 202(c), especially considering the availability of other system operators to meet any additional need. Rather, DOE's shifting reliance on seasonal alerts shows that the alerts are merely post-hoc justifications for prior orders used to accomplish DOE's goal of commandeering regional resource-planning. Even if such alerts were relevant, it is telling that there were no actual shortfalls, brownouts, or blackouts during Winter Storm Fern that would have required the specific additional capacity from J.H. Campbell versus other more cost-effective and less-polluting alternatives. Thus, the Campbell IV Order's discussion of Winter Storm Fern does not identify any particular need for which operating the Campbell Plant would have been an appropriate or even reasonable response, much less one that "best-meets" the purported emergency.

DOE is already in possession of the exhibits the States submitted in support of their petitions for rehearing of the Campbell I, II, and III Orders. The States are not resubmitting those same documents since they are incorporated by reference into the record for this petition. If DOE needs additional copies of any documents, please contact any of the signatories to this request.

KEITH ELLISON
ATTORNEY GENERAL
OF MINNESOTA

/s/ Peter Surdo
Peter Surdo
Cat Rios-Keating
Alyssa Bixby-Lawson
Ryan Pesch
Special Assistant Attorneys General
Office of the Minnesota Attorney General
445 Minnesota St., Suite 600
St. Paul, MN 55101

Dated: March 19, 2026

KWAME RAOUL
ATTORNEY GENERAL OF
THE STATE OF ILLINOIS

/s/ *Samuel C. Lukens*
Samuel C. Lukens, Assistant Attorney General
Susan L. Satter, Chief, Public Utilities Bureau
Jason E. James, Assistant Attorney General
Office of the Illinois Attorney General
115 South LaSalle, 25th Floor
Chicago, Illinois 60603

Dated: March 19, 2026

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-26-22

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota, Illinois, and Wisconsin ("the States") move to intervene and apply for rehearing of the Department of Energy's ("DOE") May 19, 2026, Order No. 202-26-22 ("Campbell V Order," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." The Campbell V Order is in effect from May 19, 2026, until August 16, 2026.[2] This is the fifth in a series of orders directing MISO to take the same actions for the same facility and based on the same alleged statutory authority and factual circumstances.

The States have an interest in and are aggrieved by Campbell V Order. *FDA v. R.J. Reynolds Vapor Co.*, 606 U.S. 226, 232–36 (2025) (defining an "adversely affected or aggrieved" party within the APA as "anyone even 'arguably within the zone of interests to be protected or

[1] All Exhibits are lettered and attached.
[2] This petition is being submitted to DOE's AskCR <askcr@hq.doe.gov> account as DOE instructs.

regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

The Campbell V Order continues the pattern established by four prior DOE Orders numbered 202-25-3 ("Campbell I"), 202-25-7 ("Campbell II"), 202-25-9 ("Campbell III"), and 202-26-16 ("Campbell IV") that also directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date of June 1, 2025, through May 18, 2026.

Multiple undersigned states requested rehearing of the Campbell I, II, III, and IV Orders and described the applicable facts, with record support, in those challenges. Exs. B–E (nested exhibits omitted). Campbell V is almost identical to Campbell IV, which extended Campbell Orders I-III. Because the legal and factual issues here directly overlap and repeat the same matters previously raised, the States hereby incorporate by reference the petitions for rehearing of the Campbell I, II, III, and IV Orders, including all arguments, exhibits, and other referenced materials, and reassert them as grounds for rehearing of the Campbell V Order.

The States will be adversely affected by the Campbell V Order in the same ways they were harmed by the Campbell I, II, III, and IV Orders, but Campbell V also compounds and increases those harms through ongoing, cumulative emissions and related impacts. The negative effects on the States were described in the prior challenges and are hereby incorporated by reference.[3]

[3] The harms include economic harm to ratepayers in the States who are saddled with the increased costs associated with operating the inefficient, coal-burning Campbell Plant, the environmental harms of operating the coal plant, and the harm caused by usurping the States' role in planning resource adequacy and generation.

The Campbell V Order compounds the errors of the prior orders for all of the reasons set forth in the Petitions for Rehearing filed by the States of Minnesota and Illinois on June 23, 2025 (Campbell I), September 19, 2025 (Campbell II), December 18, 2025 (Campbell III), and March 19, 2026 (Campbell IV).

As with the Campbell I, II, III, and IV Orders, the Campbell V Order should be rescinded because it lacked reasoned decisionmaking, exceeded DOE's authority, was not rationally tailored to meet the purported emergency, and demonstrated impermissible prejudgment of the relevant issues.

DOE's use of section 202(c) to require coal plants to remain generally available is novel. Ex. B at 11, 26–27, 34–35. Recent scholarship confirms that the executive branch has a long history of relying on experts to regulate the power grid, which it has abandoned in its attempt to take over long-term planning through emergency orders like the ones at issue here. Ex. F (Klass Essay). DOE's exercise of emergency authority to require outdated energy sources to operate is not only novel, it relies on fundamental misunderstandings of what constitutes an emergency and uses that misunderstanding to saddle ratepayers with the cost of inefficient energy production. *Id.* at 25.

The Campbell V Order misapprehends NERC's 2025 Long-Term Reliability Assessment (LTRA) to reach its findings. Ex. A at 5. As a starting point, the LTRA categorizes MISO as "normal" risk—the lowest risk designation—for 2026, and only "elevated" risk in 2027.[4] Ex. G. Further, the Order's description of the LTRA's long-term MISO forecasts omits reference to the large amounts of resources planned to be added in MISO pursuant to the "recently approved

[4] NERC's "elevated risk" designation in no way signifies an emergency condition, falls below the highest risk designation of "high risk," and is far from unusual.

Expedited Resource Addition Study (ERAS) process" that "is expected to result in additional resources in the MISO system beginning in 2028 that are not included in the model for the 2025 LTRA." *Id.* at 8. The assessment further provides the following context and explanation as to how it considers those resources in the context of its other evaluations:

> The timing of FERC's approval of MISO's ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from ERAS is expected to grow to over 20 GW by summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year's ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the 2026 LTRA . . . .

Id. at 16.

The LTRA likewise concludes that "if ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated." *Id.* at 15. Even without the planned ERAS resources, the LTRA estimates only that MISO would "fall below reserve margin targets to become a high-risk area beginning [in the end of] 2028." *Id*. This would not be a sudden or unexpected emergency during the period of the Orders.[5] Thus, not only does the Order omit the finding of merely "normal" risk during the period of the Order—which in itself rebuts any

[5] The Campbell V Order also purports to rely on winter-specific data and events. Ex. A at 6. The period governed by the Order is May 19, 2026, through August 16, 2026, and the Order identifies no risk of winter events, much less those requiring a potential emergency response, during that time period.

"emergency" designation—the Order arbitrarily ignores key evidence from the LTRA contradicting the Department's assertions as to long-term planning.

Finally, as DOE acknowledges, there is a surplus of capacity anticipated for Summer 2026. Ex. A at 6. And while DOE cites the NERC 2025 Summer Reliability Assessment, nowhere does it mention FERC's 2026 Summer Energy Market and Electric Reliability Assessment, which anticipates a 6% increase to MISO's 2025 capacity and identifies no anticipated energy shortfalls. Ex. H at 24. Indeed, FERC's presentation materials demonstrate MISO is not at elevated risk for Summer 2026. Ex. I at 8.

DOE is already in possession of the exhibits Minnesota and Illinois submitted in support of their petitions for rehearing of the Campbell I, II, III, and IV Orders. The States are not resubmitting those same documents since they are incorporated by reference into the record for this petition. If DOE needs additional copies of any documents, please contact any of the signatories to this request.

Dated: June 17, 2026

KEITH ELLISON
ATTORNEY GENERAL
OF MINNESOTA

/s/ Peter Surdo
Peter Surdo
Cat Rios-Keating
Ryan Pesch
Special Assistant Attorneys General
Office of the Minnesota Attorney General
445 Minnesota St., Suite 600
St. Paul, MN 55101

KWAME RAOUL
ATTORNEY GENERAL OF
THE STATE OF ILLINOIS

/s/ Jason E. James
Jason E. James
Assistant Attorney General
Sarah Hunger
Deputy Solicitor General
Joanna Brinkman
Complex Litigation Counsel
Illinois Attorney General's Office
201 W. Pointe Drive, Suite 7
Belleville, IL 62226
(217) 843-0322
jason.james@ilag.gov

STATE OF WISCONSIN
JOSHUA L. KAUL
ATTORNEY GENERAL

/s/ Gabe Johnson-Karp
GABE JOHNSON-KARP
Assistant Attorney General

Wisconsin Department of Justice
17 West Main Street
Post Office Box 7857
Madison, WI 53707-7857
(608) 267-8904
gabe.johnson-karp@wisdoj.gov

DOE/SEA-04

Special Environmental Analysis

For Actions Taken under U.S. Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria, Virginia

November 2006

U.S. Department of Energy
Washington, D.C.

COVER SHEET

Responsible Agency:
U.S. Department of Energy (DOE)

Cooperating Agency:
U.S. Environmental Protection Agency

Title:
Special Environmental Analysis for Actions Taken under DOE Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria, Virginia

Location:
Alexandria, VA, and Washington, DC

Contacts:

For further information on this Special Environmental Analysis (SEA) or to provide comments contact:

Mr. Anthony J. Como
SEA Document Manager
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585
Call (202) 586-5935
Fax (202) 287-5736
email: anthony.como@hq.doe.gov

For further information on the DOE National Environmental Policy Act process contact:

Ms. Carol Borgstrom, Director
Office of NEPA Policy and Compliance
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585
Call (202) 586-4600 or leave message at 1-800-472-2756
Fax (202) 586-7031
e-mail: askNEPA@hq.doe.gov

Abstract:

On December 20, 2005, the Secretary of Energy issued an emergency order, DOE Order 202-05-03, requiring Mirant's Potomac River Generating Station in Alexandria, Virginia, to operate under limited circumstances. On September 28, 2006, the Secretary extended the Order, including all of its terms and conditions, DOE Order 202-06-2, until December 1, 2006. This SEA includes descriptions of the DOE emergency orders; assessments of the direct, indirect, and cumulative impacts resulting from the emergency orders; and descriptions of alternative actions for potential future decision-making that include mitigation. This SEA covers a period of about 24 months beginning in December 2005.

Public Comment:
Simultaneously with issuance of this SEA, the Secretary is issuing another temporary extension of the emergency order, including all of its terms and conditions, DOE Order 202-07-1, until February 1, 2007. DOE is placing the document on DOE's internet websites (http://www.oe.energy.gov/permitting/372.htm and http://www.eh.doe.gov/nepa/documentspub.html) and making it available at the public reading room at DOE headquarters. An announcement of the availability of the SEA is also being made in the *Federal Register*. Comments on this SEA are due on January 8, 2007, and will be considered in any future decision-making on this matter. Due to postal security procedures, comments sent through U.S. mail may be delayed, and DOE recommends that commentors use other means.

SUMMARY

On December 20, 2005, the Secretary of Energy issued an emergency order ("DOE Order" or "Order") to Mirant Potomac River, LLC (Mirant) pursuant to Section 202(c) of the Federal Power Act (FPA). The Order directed Mirant to operate its Potomac River Generating Station ("the Plant") in Alexandria, Virginia, in specific and limited circumstances in order to reduce the risk of a blackout in the Central Washington, D.C. area, while avoiding, to the extent possible, exceedances of the National Ambient Air Quality Standards (NAAQS) (text box). The Order was to expire on September 30, 2006, but DOE issued a temporary extension of the Order, until December 1, 2006, to allow for completion of this Special Environmental Analysis (SEA). This SEA assesses impacts resulting from the Orders and from potential future alternative actions DOE may take in this matter. DOE is accepting public comment on this SEA and will consider all comments submitted in any future decision-making.

National Ambient Air Quality Standards (NAAQS)

The Clean Air Act, which was last amended in 1990, requires the Environmental Protection Agency (EPA) to set NAAQS for pollutants considered harmful to public health and the environment. EPA has set NAAQS for seven "criteria" pollutants: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), lead, carbon monoxide (CO), ozone, particulate matter less than or equal to 10 μm in aerodynamic diameter (PM_{10}), and particulate matter less than or equal to 2.5 μm in aerodynamic diameter ($PM_{2.5}$). Each NAAQS has a specific averaging time (e.g., 3-hour or 24-hour SO_2 standard) that represents the time period over which modeled air pollutant concentrations are analyzed for the purpose of determining attainment with the NAAQS. The NAAQS are implemented at the state level through State Implementation Plans (SIPs). SIPs use individual source emissions limitations to help attain and maintain the NAAQS.

In emergency situations, pursuant to 40 CFR 1506.11, the Council on Environmental Quality's (CEQ) National Environmental Policy Act of 1969 (NEPA) regulations call for agencies to consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing an environmental impact statement (EIS) that might otherwise be required for the relevant action. DOE is issuing this SEA in compliance with the "alternative arrangements" plan agreed upon with CEQ.

Background

The Plant is a 482-MW electricity generating facility located on the Potomac River in Alexandria, Virginia, about five miles (8 km) from the U.S. Capitol building (Figure S-1). The Plant consists of five generating units, each with its own exhaust stack. Because the Plant is located three miles (5 km) from the Ronald Reagan Washington National Airport and is within the flight path of the airplanes that fly in and out of that airport, it has stacks that are shorter than

normal for similar facilities. The Plant uses oil to pre-heat each of its units and then burns coal, which it receives via rail car, to generate electricity. The generated electricity is transmitted to the central business district of Washington, D.C., many Federal institutions, the Georgetown area, as well as other portions of Northwest D.C. and the D.C. Water and Sewer Authority's Blue Plains Wastewater Treatment Plant (collectively called the "Central D.C. area").

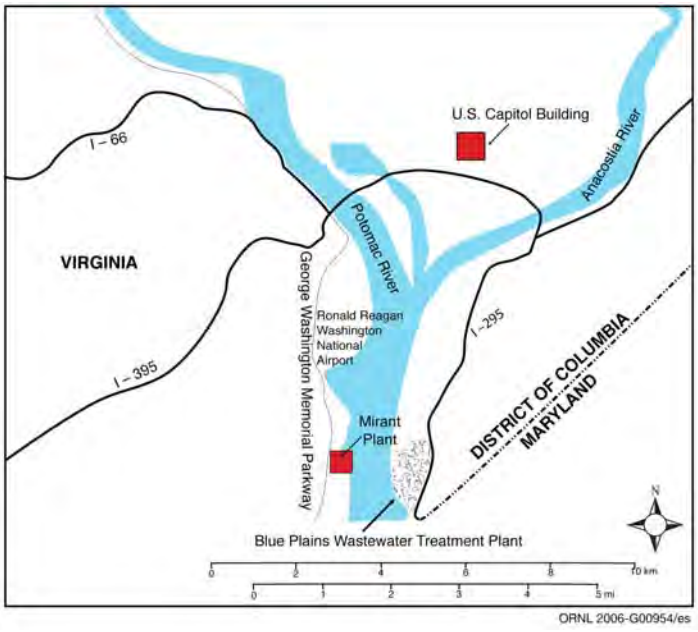


Figure S-1. The location of the Plant in relation to the central Washington, D.C. area.

The Plant site was relatively remote in 1949 when the Plant began operation. However, residential communities and commercial properties have grown up and around the Plant over the last 50 years, notably a condominium building, Marina Towers, built only 300 yards (270 m) from the Plant in the 1960s. Since 2001, residents of Marina Towers have complained about air quality impacts and associated health impacts of the Plant's operation. Since 2003, state and Federal environmental agencies have been working with Mirant to settle alleged violations of the Plant's operating permit limit for nitrogen oxide (NO_x) emissions. The alleged violations resulted in a judicial consent decree (EPA 2004) in September 2004 and an amended judicial consent decree in May 2006 (EPA 2006g). Part of the 2004 settlement required Mirant to perform a modeling analysis to predict the effect of "downwash"[1] from the Plant on ambient concentrations of several NAAQS pollutants. The study showed significant modeled exceedances of three NAAQS pollutants from downwash: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and particulate matter finer than 10 μm in aerodynamic diameter (PM_{10}). As a result of the study, on August 19, 2005, the Virginia Department of Environmental Quality (VDEQ) issued a letter to Mirant requesting that Mirant "undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shutdown of the facility." On August 24, 2005, in response to VDEQ's August 19, 2005, letter, Mirant decided to shut down all five generating units at the Plant.

[1] The September 23, 2004, judicial consent decree (EPA 2004) defined downwash as "the effect that occurs when aerodynamic turbulence induced by nearby structures causes pollutants from an elevated source (such as a smokestack) to be mixed rapidly towards the ground resulting in higher ground-level concentrations of pollutants."

DOE Action

On August 24, 2005, the District of Columbia Public Service Commission (DCPSC) filed an Emergency Petition and Complaint ("Petition") with DOE pursuant to Section 202(c) of the FPA. The Petition requested the Secretary of Energy to find that an emergency existed under Section 202(c) of the FPA and to issue an order directing Mirant to continue operation of the Plant. Section 202(c) of the FPA authorizes DOE, upon determination that an emergency exists, to "require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." The basis of the DCPSC's Petition was that the shutdown of the Plant had a drastic and potentially immediate effect on the reliability of the electricity supply of the Central D.C. area.

After receiving the Petition, DOE spent four months reviewing the facts to gather information on the shutdown of the Plant and its effect on the reliability of the Central D.C. electricity system. DOE met with private entities responsible for electricity transmission in the Central D.C. area and the regional electricity system to determine the role of the Plant in electricity reliability. DOE also met with officials from the Environmental Protection Agency (EPA) to understand the environmental situation posed by the Plant's operation, particularly with regard to the NAAQS. Meanwhile, on September 21, 2005, Mirant unilaterally restarted the Plant's unit 1 in an 8-8-8 capacity (that is, in any given 24-hour period, the unit ran for 8 hours at its maximum level, 8 hours at its minimum level, and did not run for 8 hours). Mirant also began experimental use of measures to control SO_2, specifically combustion of low-sulfur coal and injection of trona (a substance similar to baking soda) into flue gases.

During its investigation, DOE learned of the Plant's key role in providing electricity reliability to the Central D.C. area. The Plant is one of only three sources of electricity to the Central D.C. area. The other sources are two 230-kV transmission lines that deliver electricity from other regional generating sources. The Potomac Electric Power Company (Pepco) is in the process of installing two additional 230-kV transmission lines to the Central D.C. area that will provide a high level of electricity reliability to the area even in the absence of the Plant. These lines are currently expected to be placed in service in June 2007. Until then, if the Plant is not available to generate electricity and one of the two existing transmission lines goes out of service (either unexpectedly or for maintenance), the Central D.C. area would only be served by the remaining line. If the remaining line then failed, a blackout would occur, affecting many government agencies; a large number of residents and workers; and hospitals, police, and fire facilities. Since 2000, there have been 34 one-line planned outages, seven one-line unplanned outages, and two times where both lines failed simultaneously. Indeed, on December 15, 2005, during DOE's investigation, one of the 230-kV transmission lines failed unexpectedly, and the supply of electricity to the Central D.C. area depended solely on the remaining line until the morning of December 16, 2005.

After DOE's investigation, on December 20, 2005, the Secretary issued the Order stating:

> I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

DOE's Order did not direct Mirant to simply generate full power at the Plant, even though continuous, unrestricted, operation of the Plant, at all times, was requested in the Petition and would have assured a high level of electricity reliability to the Central D.C. area. Instead, the Order sought to strike an appropriate balance between environmental concerns and electricity reliability by directing Mirant to operate the Plant, but only in certain circumstances and only to limited capacity. Specifically, the Order required Mirant to (1) operate the Plant to produce the amount of power necessary to meet demand in the Central D.C. area during a planned or unplanned outage of one of the 230-kV lines and (2) in situations where both 230-kV lines are functioning, keep as many generating units in operation and take all other measures to reduce the start-up time of units not in operation for the purpose of providing electricity reliability, without causing an exceedance of the NAAQS. The Order further required Mirant to utilize pollution control equipment and measures to the maximum extent possible to minimize the magnitude and duration of any exceedance of the NAAQS during a planned or unplanned transmission line outage. The Order also contemplated continued DOE cooperation with EPA and suggested that DOE would modify the Order at a later date if EPA decided to issue an order to Mirant.

On June 1, 2006, EPA issued an Administrative Compliance Order (ACO) to Mirant. The ACO directs Mirant to operate the Plant under conditions specified in the DOE Order during line outage situations, but requires Mirant to take all reasonable steps to limit SO_2, PM_{10}, and NO_x emissions and to optimize use of trona to minimize SO_2 emissions. In non-line outage situations (i.e., in the normal course of operation), the ACO authorizes Mirant to operate the Plant under "daily predictive modeling" after certain conditions are met. Under daily predictive modeling Mirant is to model a specific operating mode for the Plant based on predicted weather conditions for the following day and operate under that mode only where the daily modeling run demonstrates that the Plant will not cause or contribute to a modeled exceedance of the 3-hr and 24-hr SO_2 and PM_{10} NAAQS. The ACO also requires Mirant to maintain alarms that alert the Plant operators if monitored average concentrations reach 80% of the standards for SO_2, including the annual SO_2 standard. In addition, the ACO requires Mirant to install and operate six new SO_2 ambient monitoring stations in the vicinity where elevated pollutant concentrations have been predicted and to conduct actual monitoring of ambient SO_2 concentrations. On

June 2, 2006, DOE directed Mirant to operate under the ACO during non-line outage situations, for the purpose of providing electricity reliability, and to continue operation in accordance with the DOE Order in line-outage situations.

DOE believes that the Order and the ACO are the product of the best available balance between providing electricity reliability to the Central D.C. area and protecting the environment and human health in Alexandria, Virginia, until the additional 230-kV lines are in service. The Order and the ACO both contain provisions to prevent NAAQS exceedances in the normal course of operation of the Plant. The only time a possible exceedance of the NAAQS is contemplated is during line-outage situations. In addition, while unplanned transmission line outages cannot be predicted, planned transmission line outages are scheduled in 2006-2007 for periods of time when demand for electricity in the Central D.C. area (and hence emissions from the Plant) is at its lowest. The 2006 amended judicial consent decree, after it is implemented, will provide limitations on NO_x emissions from the Plant.

NEPA Process and this SEA

Major Federal actions significantly affecting the human environment generally call for DOE to prepare an EIS before taking the action to analyze impacts in compliance with NEPA. However, in emergency situations, pursuant to 40 CFR 1506.11, the CEQ's NEPA regulations provide that agencies consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing an EIS. Before issuing the Order, DOE consulted with CEQ pursuant to 40 CFR 1506.11. As part of its "alternative arrangements plan," DOE agreed to provide opportunity for public involvement, continue Agency consultation, and identify alternatives for mitigation (DOE 2006). In addition, as an alternative to an EIS, CEQ agreed to preparation of this SEA. This SEA does not include an impact assessment of alternative actions that DOE might have taken instead of issuing its Order on December 20, 2005. DOE will not issue a record of decision (ROD) based on this SEA.

In the January 20, 2006, *Federal Register* notice announcing the alternative arrangements (DOE 2006), DOE requested public comments on issues to be addressed in the SEA. Comments were provided by the following organizations: the Mount Vernon group and the Virginia Chapter of the Sierra Club; the Southern Environmental Law Center on behalf of itself and the American Lung Association of Virginia; the City of Alexandria; and the Institute for Public Representation on behalf of the Potomac Riverkeeper, Inc., the Patuxent Riverkeeper, and the Anacostia Riverkeeper at Earth Conservation Corps. Commentors on the notice expressed particular concern about the following issues that are within the scope of this SEA:

- impacts on health of increased particulate emissions, especially particulate matter smaller than 2.5 microns ($PM_{2.5}$), and of increased emissions of trace metals and hazardous air pollutants (especially arsenic, beryllium, lead, chromium, cadmium, nickel, and mercury);

- the potential for any increased emissions of SO_2 and NO_x to contribute to acid rain, nutrient loading to aquatic systems, and deposition of heavy metals, and the subsequent impacts on the aquatic resources of the Chesapeake Bay and several of its tributaries, specifically the Potomac, Anacostia, and Patuxent rivers;
- impacts of trona utilization; and
- potential mitigation measures, such as use of existing transmission lines along the railroad rights-of-way of the National Railroad Passenger Corporation ("AMTRAK") and CSX Corporation and notification of nearby residents about potential NO_x exceedances.

A commentor also expressed concern about possible adverse effects of trona utilization on Plant equipment. This concern is not addressed because it is not considered to be an environmental impact.

The aim of this SEA is to describe the impacts resulting from the Order and from potential future alternative actions DOE may take in this matter. Such potential future alternative actions include allowing the Order to expire; extending the Order until the expected June 2007 in-service date of the two additional 230-kV transmission lines (or until December 2007, to account for unlikely, but possible, delays in installation); or extending the Order in modified form to include measures to mitigate impacts. Because allowing the Order to expire would place the Central D.C. area at risk of a potential blackout, this SEA describes potential impacts associated with a blackout. Potential mitigation alternatives discussed in this SEA include measures to, among other things, reduce demand for electricity in the Central D.C. area, require storage of sufficient trona at the Plant, and expedite the installation of the additional 230-kV transmission lines.

In order to give the reader a contextual way to understand the assessed impacts attributable to the Order and from a potential extension of the Order until the two new 230-kV transmission lines are in service, DOE uses assessed impacts from two different earlier Plant operating modes as a basis for comparison: the "pre-shutdown" mode of operations and the "pre-Order" operating mode. The "pre-shutdown" operating mode is based on operations in the year preceding the August 24, 2005, shutdown. The "pre-Order" mode is based on operation of the Plant during its restart of unit 1 in the 8-8-8 operating mode (approximately September - December 2005).

DOE's assessment of the effects of Plant operations considered the following resource areas and impact topics:

- Effects of any increased *air emissions*;
- *Health* effects on Plant workers and the public of any increased air pollution;
- Effects on *water quality* due to atmospheric deposition of air pollutants from the Plant and changes in Plant water use and releases;
- *Ecological* effects due to acid deposition, changes in water quality, and changes in water use, including impacts to special status species;
- *Waste management* impacts, particularly impacts of trona utilization;

- *Transportation impacts* from increased shipping of coal and trona to the Plant and of wastes away from the Plant; and
- *Environmental justice* impacts.

It is important to understand the process DOE used to assess impacts from the Order and from a potential additional extension of the Order. Understanding DOE's approach for modeling air quality impacts is particularly important because (1) air quality is the most significant environmental concern associated with the Plant's operation and (2) many other impacts, including impacts to human health, are based on modeled estimates of air impacts. For its air analysis DOE used EPA's AERMOD model to assess modeled concentrations of SO_2 and PM_{10} as a result of the Order (split into two time periods: before the ACO and after the ACO) and a potential extension of the Order (until July 2007 and December 2007). DOE focused on modeling concentrations of SO_2 and PM_{10} because the original downwash study that prompted the shutdown of the Plant emphasized SO_2, PM_{10}, and NO_x (and the amended judicial consent decree between EPA and Mirant [EPA 2006g] deals with NO_x.) In modeling concentrations of SO_2 and PM_{10}, DOE used several simplifications and made a number of key assumptions that are essential to understand before interpreting the modeled results:

- *Assumptions in Modeling*
  - DOE's modeling of SO_2 and PM_{10} assumed weather conditions from 2001 because EPA had shown that 2001 resulted in predictions of more adverse air quality than any of the other years during the period from 2000 through 2004. Therefore, DOE's modeling results likely overestimate impacts.
  - DOE's assessment of impacts to the health of people living near the Plant is based on estimated exposures to $PM_{2.5}$. DOE used air dispersion modeling for PM_{10} to estimate exposures to $PM_{2.5}$. Therefore, to the extent that DOE's modeled air quality results overestimate impacts, the health results also likely overestimate impacts. In addition, DOE did not analyze factors such as health status or activity level that affect the likelihood of actual health impacts to specific individuals. Consequently, the results of DOE's health impact analysis represents an estimate of the impact to the population, rather than the likely impact to any specific individual.

- *Assumptions and Simplifications about Operations*
  - For the period from December 21, 2005, through March 31, 2006, DOE used hourly emissions data provided by Mirant to model SO_2 and PM_{10} emissions. (For the two days for which data were not provided, DOE assumed operations were identical to the preceding day.) To model the air quality impacts of operations during the period April 1 through May 31, 2006, DOE assumed that Mirant operated the Plant to the maximum level described in the operating plan supplements that Mirant provided to DOE.

- For operations during daily predictive modeling, DOE assumed that the Plant would generate the maximum allowed power by using a combination of increased trona injection and reduced power levels to assure that its operations would not contribute to an exceedance of the 24-hour-average NAAQS limit for SO_2 concentrations in the normal course of business (i.e., no line outage). DOE did not simulate predictive modeling for the 3-hour SO_2 standard because the computational effort required to calculate average concentrations for all possible 3-hour periods for each of the over 1,700 modeled locations near the Plant was judged to be excessively large for the information to be gained. Consequently, the SEA reports modest modeled exceedances of the 3-hour SO_2 standard that are not expected to actually occur. The SEA also reports exceedances of the annual standard because operating close to the 24-hour limit day after day raises the long-term average. However, because the ACO requires Mirant to monitor SO_2 concentrations and adjust operation of the Plant to meet SO_2 standards for all averaging periods, actual exceedances of the annual standard are not expected to occur.

Preliminary data from the six new SO_2 monitoring stations that Mirant installed during the summer of 2006, pursuant to the ACO, provides an initial look at actual impacts from the Plant under the ACO's daily predictive modeling. DOE's modeling results are not directly comparable to the monitored data because DOE's modeling used average emissions and historical weather data rather than current-year data. However, monitored data can be compared with the follow-up modeling that Mirant is conducting under the ACO, using actual concurrent emissions and weather data. For the period June 17, 2006, to September 17, 2006, the maximum monitored daily-average SO_2 concentration for the monitors ranged from 4 to 63 $\mu g/m^3$, whereas Mirant's follow-up modeling gave maximum daily-average SO_2 concentrations from 25 to 570 $\mu g/m^3$. Thus, monitored concentrations of SO_2 are much lower than Mirant's follow-up modeled concentrations. EPA will be evaluating the reasons for this large discrepancy between the actual monitored data and follow-up modeling throughout the course of the ACO. Should DOE extend the Order on December 1, 2006, DOE will make monitored data (as submitted by Mirant to EPA under the ACO) available on the website it maintains to provide information about this matter, http://www.oe.energy.gov/permitting/372.htm.

Table S.1 summarizes the assessed impacts of the Order, both before and after the initiation of daily predictive modeling. It also includes impacts of the temporary extension of the Order and a potential additional extension of the Order until December 2007, assuming a 6-month delay in the installation of the additional 230-kV lines. Finally, the table presents the assessed impacts associated with the "pre-shutdown" and "pre-Order" modes of operation of the Plant to give the reader a basis for comparison.

Table S.1 Summary of impacts of Plant operations (See text for details.)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 [1]
AIR QUALITY				
SO_2	Modeled maximum concentration values for SO_2 in ambient air exceed NAAQS limits for all averaging periods (i.e., 3-hour, 24-hour, and annual).	Modeling shows no exceedance of NAAQS limit for any averaging period.	For operations before the commencement of daily predictive modeling (i.e., before July 1, 2006), there are no modeled SO_2 or NO_x exceedances during non-line outage situations. For operations during line outages (21 days in January 2006) modeled maximum concentration values for SO_2 in ambient air exceed SO_2 NAAQS limits for all averaging periods. For operations after the commencement of daily predictive modeling (i.e., starting July 1, 2006), modeling shows no exceedances of 24-hour average SO_2 NAAQS limit because of requirements of predictive modeling. Modeling shows exceedances for other averaging periods, but because the ACO requires compliance with SO_2 NAAQS in non-line outage situations, actual exceedances are not expected.	For operations during non-line outage periods, modeling shows no exceedances of 24-hour average SO_2 NAAQS limit because of requirements of predictive modeling. Modeling shows exceedances for other averaging periods, but because the ACO requires compliance with SO_2 NAAQS in non-line outage situations, actual exceedances are not expected. For operations during line outages, modeled maximum concentration values for SO_2 in ambient air exceed SO_2 NAAQS limits for all averaging periods.

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 [1]
PM_{10}	Modeled maximum concentration values for PM_{10} in ambient air meet NAAQS annual standard but exceed limit for 24-hour averaging period. [2]	Modeled maximum concentration values for PM_{10} in ambient air meet NAAQS standards for both the annual and 24-hour averaging periods. [3]		
$PM_{2.5}$	Background concentrations measured by VDEQ while the Plant was operating at pre-shutdown levels are below the current NAAQS limit for 24-hour averaging period (65 $\mu g/m^3$) and are slightly below the current NAAQS annual limit (15 $\mu g/m^3$), but exceed the NAAQS limit for the 24-hour averaging period (35 $\mu g/m^3$) that will take effect in December 2006. As a result of the background contribution, estimated maximum concentration values in ambient air (including background) for all operating modes exceed the NAAQS annual limit and the December 2006 limit for the 24-hour averaging period, both at ground level and the top of Marina Towers. Adding estimated Plant contributions to background concentrations involves some double counting of Plant effects.			
	Estimated maximum concentration values in ambient air (including background) at ground level and the top of Marina Towers exceed current and future NAAQS limits for both 24-hour and annual averaging periods.	Estimated maximum concentration values in ambient air (including background) at ground level and the top of Marina Towers are lower than for pre-shutdown operations and meet the current NAAQS limit for the 24-hour averaging period, but exceed the annual and 24-hr limits that will take affect in December 2006.	Estimated maximum concentration values in ambient air (including background) at ground level are lower than for pre-shutdown operations but higher than for pre-Order operations and meet the current NAAQS limit for the 24-hour averaging period but exceed the annual and 24-hr limits that will take affect in December 2006. Estimated maximum concentration values at the top of Marina Towers are lower than for pre-shutdown operations, but exceed current and future NAAQS limits for both 24-hour and annual averaging periods.	

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 [1]
$PM_{2.5}$ (continued)	Plant contributions to ground-level $PM_{2.5}$: 38 $\mu g/m^3$ for 24-hr 5.7 $\mu g/m^3$ for annual	Plant contributions to ground-level $PM_{2.5}$: 9.2 $\mu g/m^3$ for 24-hr 2.0 $\mu g/m^3$ for annual	Plant contributions to ground-level $PM_{2.5}$: 25 $\mu g/m^3$ for 24-hr 2.4 $\mu g/m^3$ for annual	Plant contributions to ground-level $PM_{2.5}$: 23 $\mu g/m^3$ for 24-hr 4.0 $\mu g/m^3$ for annual
	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 76 $\mu g/m^3$ for 24-hr 7.8 $\mu g/m^3$ for annual	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 4.8 $\mu g/m^3$ for 24-hr 1.0 $\mu g/m^3$ for annual	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 41 $\mu g/m^3$ for 24-hr 3.9 $\mu g/m^3$ for annual	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 43 $\mu g/m^3$ for 24-hr 5.7 $\mu g/m^3$ for annual
Contributions to ozone pollution from NO_x	Operations estimated to emit 2,300 tons[3] of NO_x (which contributes to formation of ozone) over 285 days (rate of about 3,000 tons/yr)	Operations estimated to emit 640 tons of NO_x over 285 days (rate of about 820 tons/yr)	Operations estimated to emit 2,000 tons of NO_x over 285 days (rate of about 2,600 tons/yr)	Operations estimated to emit 3,700 tons of NO_x over 15 months (rate of about 3,000 tons/yr)
Mercury emissions	Operations estimated to emit mercury at a rate of 116 lb/yr or 91 lb over 285 days[3]	Operations estimated to emit 21 lb mercury over 285 days (rate of about 28 lb/yr)	Operations estimated to emit 79 lb mercury over 285 days (rate of about 101 lb/yr)	Operations estimated to emit mercury at a rate of 116 lb/yr or 146 lb over 15 months
Carbon monoxide and lead	Because ambient concentrations of carbon monoxide and lead are far below NAAQS limits and because coal plants are not important sources of either pollutant, DOE did not model Plant contributions to ambient levels for either pollutant.			
Contributions to global climate change	Operations estimated to release CO_2 (a greenhouse gas that contributes to global warming) at a rate of 2,000,000 tons/yr from coal use	Operations estimated to release CO_2 at a rate of 488,800 tons/yr from coal use	Operations estimated to release CO_2 at a rate of 1,766,500 tons/yr from coal and trona use	Operations estimated to release CO_2 at a rate of 2,007,500 tons/yr from coal and trona use

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 [1]
HUMAN HEALTH				
Premature mortality due to air pollution exposure	Expected incidence of premature mortality among the 144,000 adults in 36-mi^2 area[3] around the Plant of 3.8 per year	Expected incidence of premature mortality among the 144,000 adults in 36-mi^2 area around the Plant of 0.77 per year	Expected incidence of premature mortality among the 144,000 adults in 36-mi^2 area around the Plant of 1.3 over 285-day duration of the Order (annual rate of 1.7)	Expected incidence of premature mortality among the 144,000 adults in 36-mi^2 area around the Plant of 2.9 over 15-month duration of the potential extension (annual rate of 2.3)
WATER QUALITY				
Nitrogen loading to Chesapeake Bay	Operations deliver nitrogen to the Bay at an estimated rate of 170,000 lb/yr	Operations deliver nitrogen to the Bay at an estimated rate of 47,000 lb/yr	Operations deliver nitrogen to the Bay at an estimated rate of 150,000 lb/yr	Operations deliver nitrogen to the Bay at an estimated rate of 170,000 lb/yr
Acid deposition	Plant emissions of SO_2 and NO_x contribute to regional acid deposition.	SO_2 and NO_x emissions are 28% of pre-shutdown levels	NO_x emissions are 87% of pre-shutdown levels; SO_2 emissions are less than 45% of pre-shutdown levels	NO_x emissions are similar to pre-shutdown levels, but SO_2 emissions are 50% of pre-shutdown levels
	Negligible impacts to water quality in nearby watersheds, because these watersheds are well buffered against acid rain.			
Effects of changes in Plant water use and releases	Effects of many years of Plant operations are among the natural and human factors reflected in the existing water quality conditions of the Potomac River	Reduced water and thermal discharge rates, compared with pre-shutdown operations, could contribute to improved water quality in the Potomac River	Impacts intermediate between pre-Order and pre-shutdown operations	Impacts similar to pre-shutdown operations

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 [1]
ECOLOGICAL RESOURCES				
Acid deposition	Acid deposition resulting from Plant operations has negligible impacts on terrestrial and aquatic biological resources because (1) the soils in the nearby river and stream watersheds where emissions from the Plant are likely to fall are well buffered and (2) vegetation has actively grown near and next to the Plant even at "pre-shutdown" levels.			
Changes in water quality	Ecological changes to the Potomac River and Chesapeake Bay due to changes in nutrient loading induced by the Order or a potential extension of the Order would be minimal.			
	No effects from trona (no use of trona).	No effects from trona (assessment assumes no use of trona).	Selenium and arsenic leached from solid wastes produced with trona use could adversely affect biota in Mataponi Creek. Monitoring of collected landfill leachate and stormwater for selenium should identify the potential for problems before discharges occur, but the current discharge permit does not require monitoring for arsenic.	
Changes in water use	Effects of Plant operations under the Order or a potential extension of the Order through December 2007 would not have a major impact on aquatic biota, although the impacts from entrainment and impingement would be greater than for the "pre-Order" mode.			
Special status species	No adverse impacts to any special status species would be expected to result from Plant operations.			

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 [1]
WASTE MANAGEMENT				
Solid waste	With indefinite continuation of Plant operations in pre-shutdown mode, the Mirant Brandywine ash landfill would be able to receive fly ash until mid-2012.	With indefinite continuation of Plant operations in pre-Order mode, the Mirant Brandywine landfill would be able to receive fly ash until mid-2015.	With indefinite continuation of Plant operations at operating levels under the Order, including use of trona, the Mirant Brandywine ash landfill would be able to receive fly ash until early 2010.	
	Waste characteristics would be unchanged.	Waste characteristics would be unchanged (assessment assumes no use of trona).	Trona in Plant solid wastes may increase the leaching of selenium and arsenic from the landfill. Current monitoring requirements at the landfill include monitoring for selenium in collected leachate and stormwater before water is discharged to surface water, but do not include monitoring for arsenic. Groundwater monitoring does not include selenium or arsenic.	
TRANSPORTATION				
Impacts from road and rail traffic	Neither rail nor truck traffic associated with Plant operations have an important effect on local traffic near the Plant.			
	Transport of Plant fly ash to the Mirant Brandywine ash landfill contributes to existing traffic problems on Maryland Route 381, and increased traffic associated with operations under the Order, including the temporary extension of the Order and any potential extension of the Order increases this effect. The State Highway Administration is requiring that Mirant address problems at certain intersections along Maryland Route 381 that have been rated as having “failing” levels of service, and Maryland-National Capital Park and Planning Commission staff have recommended ways to address traffic impacts on North Keys Road.			

Table S.1 (Continued)

Resources and Topics	Pre-shutdown (prior to August 24, 2005)	Pre-Order (Sept. - Dec. 20, 2005)	Order (Dec. 20, 2005 - Oct. 1, 2006)	Temporary extension of Order (until Dec. 1, 2006) and potential extension until Dec. 2007 [1]
ENVIRONMENTAL JUSTICE				
Impacts to minority and low-income populations	Because of their proximity to the Plant, residents of block groups 1 and 2 (which are neither low-income nor minority populations) experience higher air pollution from Plant emissions than residents of block groups 3 (which is identified as a low-income population) and 4 (which is identified as a minority population). DOE has not identified any different or unique ways that these or other minority and low-income populations in the area could be exposed to Plant air pollutants or otherwise affected by the Order or its potential extension. Consequently, the minority and low-income populations in block groups 3 and 4 do not suffer "disproportionately high and adverse human health or environmental effects" related to air pollutant emissions from the Plant.			

[1] For several resources and topics, emissions and impacts are greater under an extension of the Order than under the Order because during the initial months of the Order the Plant operated at lower levels than result from daily predictive modeling.

[2] EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM_{10} standard, effective December 18, 2006.

[3] To convert tons to metric tons, multiply by 0.91. To convert lbs to kg, multiply by 0.45. To convert square miles to square km, multiply by 2.60.

[This page intentionally left blank]

Special Environmental Analysis

For Actions Taken under U.S. Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria, Virginia

DOE/SEA-04

U.S. Department of Energy
Washington, D.C.

November 2006

[This page intentionally left blank]

TABLE OF CONTENTS

LIST OF FIGURES vii

LIST OF TABLES ix

ACRONYMS AND ABBREVIATIONS xi

1. PURPOSE AND NEED FOR THE DOE ACTION 1
- 1.1 Introduction 1
- 1.2 Purpose and Need for Agency Action 2
- 1.3 Background 2
  - 1.3.1 Electrical Reliability 2
  - 1.3.2 Environmental and Health Issues 3
  - 1.3.3 Detailed History 3
- 1.4 National Environmental Policy Act (NEPA) Process 10
- 1.5 Public Involvement 11
- 1.6 Scope of the Analysis 12

2. DESCRIPTION OF THE MIRANT POTOMAC RIVER GENERATING STATION 14
- 2.1 Site Layout 14
- 2.2 Plant Equipment and General Operation 14
- 2.3 Resource Requirements 17
- 2.4 Waste and Effluents 18
  - 2.4.1 Air Emissions 18
  - 2.4.2 Water Effluents 19
  - 2.4.3 Solid Wastes 20
- 2.5 Changes to the Plant Since the DOE Order 21

3. AFFECTED ENVIRONMENT 23
- 3.1 Climate and Air Quality 23
  - 3.1.1 Climate 23
  - 3.1.2 Air Quality 24
- 3.2 Human Health 27
- 3.3 Water Resources and Water Quality 27
  - 3.3.1 Physical Setting and Hydrology 27
    - 3.3.1.1 Potomac River 28
    - 3.3.1.2 Anacostia River 29
    - 3.3.1.3 Rock Creek 29
    - 3.3.1.4 Patuxent River 30
    - 3.3.1.5 Chesapeake Bay 30
  - 3.3.2 Water Quality 31
    - 3.3.2.1 Potomac River 31
    - 3.3.2.2 Anacostia River 32

3.3.2.3 Rock Creek . . . 33
3.3.2.4 Patuxent River . . . 33
3.3.2.5 Chesapeake Bay . . . 33
3.3.2.6 Acid deposition . . . 35
3.4 Ecological Resources . . . 35
3.4.1 Terrestrial Resources . . . 35
3.4.1.1 Vegetation . . . 35
3.4.1.2 Wildlife . . . 36
3.4.1.3 The Mirant Plant site . . . 37
3.4.2 Aquatic Resources . . . 37
3.4.2.1 Potomac River . . . 37
3.4.2.2 Anacostia River . . . 38
3.4.2.3 Rock Creek . . . 39
3.4.2.4 Patuxent River . . . 39
3.4.2.5 Chesapeake Bay organisms . . . 40
3.4.2.6 Chesapeake Bay stresses . . . 40
3.4.3. Wetlands and Riparian Habitats . . . 41
3.4.4. Special Status Species . . . 41
3.4.4.1 Federally listed species . . . 41
3.4.4.2 State-listed species . . . 43
3.5 Waste Management . . . 43
3.6 Transportation Resources . . . 44
3.6.1 Rail . . . 45
3.6.2 Road . . . 45
3.7 Minority and Low-Income Populations . . . 48

4. PLANT OPERATIONS, ASSUMPTIONS, AND ENVIRONMENTAL CONSEQUENCES . . 51
4.1 General Plant Operations as Authorized by the DOE Order . . . 51
4.1.1 Operations as Authorized by the DOE Order until the Administrative Compliance Order (ACO) . . . 51
4.1.2 Operation under the ACO . . . 52
4.1.2.1 Operations during non-line outage situations . . . 52
4.1.2.2 Operations during line outage situations . . . 53
4.2 Assumptions and Data Used in SEA to Model Plant Operations . . . 53
4.2.1 Pre-Shutdown Operations . . . 54
4.2.2 Pre-Order Operations . . . 54
4.2.3 Operations under the Order and Potential Extension . . . 55
4.3 Environmental Consequences . . . 58
4.3.1 Air Quality . . . 58
4.3.1.1 Modeling methods and assumptions . . . 59
4.3.1.2 Uncertainties in modeling . . . 62
4.3.1.3 Modeling results for SO_2 and PM_{10} emissions . . . 64
4.3.1.4 Monitored SO_2 data . . . 68
4.3.1.5 Other air pollutants . . . 70
4.3.1.6 General conformity requirement . . . 75

4.3.1.7 Global climate change 77
4.3.2 Human Health 79
4.3.2.1 Analytical approach 80
4.3.2.2 Results 81
4.3.3 Water Quality 84
4.3.3.1 Direct impacts to the Potomac River 85
4.3.3.2 Indirect impacts to regional water quality 86
4.3.4 Ecological Resources 89
4.3.4.1 Acid deposition 89
4.3.4.2 Impact of water quality changes 90
4.3.4.3 Impacts of changes in water use 91
4.3.4.4 Special status species 94
4.3.5 Waste Management 95
4.3.5.1 Impacts on landfill capacity 95
4.3.5.2 Effects of trona use on the environmental consequences of waste management 98
4.3.6 Transportation Resources 102
4.3.6.1 Pre-shutdown operations 103
4.3.6.2 Pre-Order operations 104
4.3.6.3 Operations under the DOE Order, temporary extension, and potential additional extensions 104
4.3.7 Environmental Justice 106

5. ALTERNATIVES FOR FUTURE DECISION-MAKING 108
5.1 Allow the Order to Expire 108
5.2 Extend the Order as Currently Written 109
5.3 Extend the Order with Mitigation Measures 109
5.3.1 Improve Plant Operations and Pollution Control Measures 109
5.3.2 Reduce Exposure to Pollution 110
5.3.3 Manage the Demand for Electricity in the Central D.C. Area 112
5.3.4 Use Alternative Sources for Generating Electricity 113
5.3.5 Expedite the Installation of Additional Transmission Lines or Encourage the Use of Other Existing Lines 113

6. REGULATORY CONSULTATION AND COMPLIANCE 115

7. REFERENCES 116

8. LIST OF PREPARERS 128

APPENDIX A DOE Emergency Orders A-1

APPENDIX B EPA's Administrative Compliance Order for the Mirant Potomac River Generation Station B-1

APPENDIX C *Federal Register* Notice of Emergency Action and Correspondence with the Council on Environmental Quality C-1

APPENDIX D Consultation Letters with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service D-1

APPENDIX E Organizational Conflict of Interest Statement E-1

APPENDIX F Glossary F-1

LIST OF FIGURES

Figure 2-1. The location of the Plant in relation to the central Washington, D.C. area. 14
Figure 2-2. Aerial photo showing the Plant and surrounding residences. 15
Figure 2.1-1. The site layout of Mirant's Potomac River Generating Station. 16
Figure 2.4-1. The location of and access routes to the Brandywine Fly Ash Facility used for disposal of solid wastes from the Plant. 21
Figure 3.1-1. Wind rose for Ronald Reagan Washington National Airport, 2000-2004 weather data 24
Figure 3.3-1. The Chesapeake Bay watershed includes the Patuxent and Potomac rivers. 28
Figure 3.3-2. The Chesapeake Bay watershed near the Plant includes the Potomac, Patuxent, and Anacostia rivers. 28
Figure 3.3-3. Location of features mentioned in the text. 30
Figure 3.4-1. Location of National Park Service trail that passes the Plant. 36
Figure 3.6-1. Access routes near the Mirant Plant. 45
Figure 3.7-1. Block Groups 1-4 within Census Tract 2018.01. 49
Figure 4.2-1. Monthly average power generation for September 2004 through August 2005. 54
Figure 4.3.1-1. Map of receptor grid points for atmospheric dispersion modeling. 59

[This page intentionally left blank]

LIST OF TABLES

Table 1.3-1. Chronology of major actions and events related to the Plant 7
Table 2.3-1. Ranges of values for trace metal concentrations in as-mined samples of Appalachian coals 17
Table 2.4-1. Water quality of Plant intake water and cooling water effluent 20
Table 3.1-1. National Ambient Air Quality Standards for criteria pollutants 25
Table 3.1-2. Ambient air quality in the vicinity of the Plant, 2004 26
Table 3.3-1. NPDES-permitted discharge limits for the Blue Plains Wastewater Treatment Plant 32
Table 3.6-1. Roads traveled by the ash removal trucks between Henry Street and the Brandywine Fly Ash Facility 46
Table 3.6-2. Traffic impacts projected in Mirant's *Application for Special Exception* for the road intersections used to access the Brandywine Fly Ash Facility 48
Table 3.7-1. Minority and low-income data for census tract 2018.01 and its block groups . . . 50
Table 4.3.1-1. Modeled maximum ambient SO_2 and PM_{10} concentrations ($\mu g/m^3$) for Plant operations among all receptor locations 66
Table 4.3.1-2. Modeled maximum ambient SO_2 and PM_{10} concentrations ($\mu g/m^3$) for Plant operations among all receptor locations for a potential extension of the Order 69
Table 4.3.1-3. Annualized carbon dioxide emissions (tons/year) from the Mirant Plant during operational periods under analysis in this report 79
Table 4.3.2-1. Expected incidence of short- and long-term health effects resulting from Mirant Plant operations for the population of the eastern United States 85
Table 4.3.5-1. Impact of Plant operations on remaining operating life of the Brandywine ash landfill 97
Table 4.3.5-2. Concentrations of major constituents and trace elements in samples of Plant fly ash resulting from operations with and without trona injection. 100

[This page intentionally left blank]

ACRONYMS AND ABBREVIATIONS

µg	micrograms (i.e., millionths of a gram)
µm	micrometers (i.e., millionths of a meter)
ACO	Administrative Compliance Order
Btu	British thermal unit
C	Celsius
CAA	Clean Air Act
CEQ	Council on Environmental Quality
CFR	*Code of Federal Regulations*
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
CT	census tract
D.C.	District of Columbia
DCPSC	District of Columbia Public Service Commission
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
F	Fahrenheit
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FR	*Federal Register*
ft	feet
ft^2	square feet
FWS	U.S. Fish and Wildlife Service
gal	gallons
ha	hectare
hr	hour
kg	kilogram
km	kilometer
km^2	square kilometer
kV	kilovolt
L	liter
lb	pound(s)
LLC	Limited Liability Company
LOS	level-of-service
m	meter
m^2	square meter
m^3	cubic meter
MBtu	million British thermal units
MES	Model Evaluation Study
mg	milligrams (i.e., thousandths of a gram)
mi	mile
mi^2	square mile
min	minute
MSL	mean sea level
MW	megawatts
MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
O_3	ozone
Pb	lead
Pepco	Potomac Electric Power Company
PJM	PJM Interconnection, LLC
Plant	Mirant's Potomac River Generating Station (in Alexandria, Virginia)
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 µm
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 µm
ppb	parts per billion
ppm	parts per million
RCRA	Resource Conservation and Recovery Act
ROD	*Record of Decision*
SEA	special environmental analysis
SIP	state implementation plan
SO_2	sulfur dioxide
TCLP	Toxicity Characteristic Leaching Procedure
U.S.	United States
U.S.C.	United States Code
VDEQ	Virginia Department of Environmental Quality
yd^3	cubic yard
yr	year

EXPONENTIAL NOTATION: Some values in the text and tables of this document are expressed in exponential notation. An exponent is the power to which the expression, or number, is raised. This form of notation is used to conserve space and to focus attention on comparisons of the order of magnitude of the numbers (see examples):

1×10^{4}	=	10,000
1×10^{2}	=	100
1×10^{0}	=	1
1×10^{-2}	=	0.01
1×10^{-3}	=	0.001

Metric Conversions Used in this Document:

Multiply	By	To Obtain
	Length	
inch (in.)	2.54	centimeters (cm)
feet (ft)	0.30	meters (m)
yards (yd)	0.91	meters (m)
miles (mi)	1.61	kilometers (km)
	Area	
acres (ac)	0.40	hectares (ha)
square feet (ft^2)	0.093	square meters (m^2)
square yards (yd^2)	0.84	square meters (m^2)
square miles (mi^2)	2.60	square kilometers (km^2)
	Volume	
gallons (gal)	3.79	liters (L)
cubic feet (ft^3)	0.028	cubic meters (m^3)
cubic yards (yd^3)	0.76	cubic meters (m^3)
	Weight	
ounces (oz)	28.4	grams (gm)
pounds (lb)	0.45	kilograms (kg)
short ton (ton)	0.91	metric ton (t)

1. PURPOSE AND NEED FOR THE DOE ACTION

1.1 Introduction

This special environmental analysis (SEA) focuses on the environmental impacts of operations at the coal-fired Potomac River Generating Station (the "Plant") in Alexandria, Virginia, as a result of a U.S. Department of Energy (DOE or "Department") emergency order (the "DOE Order" or "Order") (Appendix A) issued on December 20, 2005, pursuant to Section 202(c) of the Federal Power Act (FPA)[1]. The Plant is owned by Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant). (See text box.)

On August 24, 2005, Mirant shut down operation of the Plant to respond to concerns about the Plant's impacts on air quality. (See Section 1.3.3.) On August 24, 2005, DOE received an Emergency Petition and Complaint from the District of Columbia (D.C. or District) Public Service Commission (DCPSC 2005). That petition requested DOE to direct Mirant to continue operation of the Plant. The basis for the petition was that shutdown of the Plant reduced the reliability of the electrical supply (Section 1.3.1) to much of the central business district of the District of Columbia, many Federal institutions, the Georgetown area in D.C., other portions of Northwest D.C., and the D.C. Water and Sewer Authority's Blue Plains Wastewater Water Treatment Plant (collectively referred to herein as the "Central D.C. area"), placing these electrical customers at risk of a blackout (DCPSC 2005).

After receiving the petition from the D.C. Public Service Commission, DOE undertook an exhaustive review of the facts. (See Section 1.3.3 for a detailed history.) Based on this

Entities involved in delivering power in the Central D.C. area

Mirant owns and operates electrical power generating plants, including the Potomac River Generating Station in Alexandria, Virginia.

Potomac Electric Power Company (Pepco) owns and operates transmission lines and is responsible for supplying electricity to retail customers in D.C. and parts of Maryland.

PJM Interconnection, LLC (PJM) is the transmission organization responsible for coordinating the regional electric power grid and wholesale electricity market in D.C., Maryland, Virginia, Delaware, New Jersey, West Virginia, and parts of Indiana, Illinois, Kentucky, Michigan, Ohio, Pennsylvania, and Tennessee. PJM keeps the electricity supply and demand in balance by telling power producers how much power to generate.

[1] Section 202(c) of the FPA vests in the Secretary of Energy the authority to issue an order when "an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes..." [16 U.S.C. Section 824a(c)]

extensive evaluation, the Secretary of the Energy on December 20, 2005, issued Order 202-05-03 (the "DOE Order") directing Mirant to generate electricity at the coal-fired Plant under certain, limited circumstances.

DOE is issuing this SEA in compliance with the "alternative arrangements" plan agreed upon with the Council on Environmental Quality (CEQ) pursuant to 40 CFR 1506.11. This SEA covers a period of about 24 months beginning with the issuance of the Order. The time period for DOE's original Order ended at 12:01 am on October 1, 2006; on September 28, 2006, the Secretary of Energy extended the Order for two months, until 12:01 am on December 1, 2006. However, this SEA covers the full 24-month period at the end of which the Potomac Electric Power Company (Pepco) (text box) expects to have completed construction of new transmission lines that will provide additional electrical service to customers in the Central D.C. area.

1.2 Purpose and Need for Agency Action

The purpose and need for DOE's action was to respond to the emergency reliability situation that had been brought on by shutdown of operations at the Mirant Potomac River Generating Station.

1.3 Background

1.3.1 Electrical Reliability

The Plant has been operating since 1949. It is one of three sources that provide electricity to Central D.C. area customers. The other sources are two 230,000-volt (230-kV) transmission lines that deliver electricity from other regional generating sources. Two additional generating stations exist in close physical proximity to the Central D.C. area, but they are not connected by transmission lines that allow the electricity they produce to be delivered to that area. Thus, if the Plant is not available to generate electricity and one of the two transmission lines serving the Central D.C. area goes out of service, electricity would be supplied to that area by only the one remaining transmission line. Should the remaining line fail for any reason, a potentially extended blackout would occur in the Central D.C. area. If both lines are down and one of them could not be brought back into service immediately, it would take at least 28 hours to bring the Plant into full operation, during which time much of the Central D.C. area would be without electricity. Transmission line outages can be either planned in order to perform periodic maintenance or unexpected. The duration of an outage can be several days or weeks for maintenance or up to several weeks in the event of a major, unexpected equipment failure.

An important consideration in issuing the Order was the facilities and functions that would be adversely affected by an extended blackout. The Central D.C. area includes facilities of

all three branches of the U.S. government that are critically important to the Nation's national security, law enforcement, and regulatory functions. The Central D.C. area also includes hundreds of thousands of residents and workers and many public safety and protection facilities (e.g., hospitals, police and fire stations). Moreover, within 24 hours of a Central D.C. blackout the Blue Plains Wastewater Treatment Plant would begin to discharge untreated sewage into the Potomac River. Thus, an extended blackout would severely impact critical portions of the Nation's government with potentially adverse national effects. It would also result in hardship and potential physical risk to many people from loss of heat or cooling, elevator outages, medical equipment failure, and other causes.

In 2005 Pepco received permission from the D.C. Public Service Commission to construct two additional 230-kV lines that would supply electricity to the Central D.C. area and two new 69-kV lines that would supply electricity to the Blue Plains Wastewater Treatment Plant. The two 69-kV lines have since been constructed. Once the new 230-kV lines are completed, these lines will provide a high level of electricity reliability in the Central D.C. area, even in the absence of production from the Plant. However, it could be mid- to late-2007 before the new lines are installed and operating. Pepco's schedule for completing installation of the new transmission lines has the lines going into service in June 2007.

1.3.2 Environmental and Health Issues

Residents in the area of the Plant have been concerned about the environmental and health impacts of its air emissions for years (SPROL 2005). However, the D.C. Public Service Commission, Pepco, and PJM Interconnection, LLC (PJM) (text box) have contended that there were no actual monitored exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act (CAA) during the Plant's operation in the period before Mirant shut it down on August 24, 2005, and that operation of the Plant at full power at any time during that period did not exceed the emissions limits contained in the Plant's operating permit (DOE Order 202-05-03).

1.3.3 Detailed History

This section describes the actions taken by DOE in relation to the DOE Order and to the Plant. Table 1.3-1, at the end of the section, provides a more complete chronology of the major actions and events related to the DOE Order and the Plant.

Mirant and the Virginia Department of Environmental Quality (VDEQ) entered into an Order by Consent on September 23, 2004. Under that order Mirant performed a dispersion modeling analysis to assess the effect of downwash[2] of air emissions from the Plant and to

[2] The September 23, 2004, judicial consent decree (EPA 2004) defined downwash as "the effect that occurs (continued...)

determine whether the Plant could cause or contribute to significant localized exceedances of the NAAQS (ENSR 2005). This study, known as the downwash study, used computer modeling to predict ambient concentrations of pollutants emitted by the Plant under certain weather and atmospheric conditions.

Mirant submitted the results of the downwash study to the VDEQ in August 2005. After reviewing the study, VDEQ sent Mirant a letter dated August 19, 2005, stating that the modeling results showed that under certain atmospheric conditions the Plant's operations could result in, cause, or substantially contribute to modeled violations of the NAAQS for sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and particulate matter with an aerodynamic diameter less than or equal to 10 µm (PM_{10}).

In its August 19, 2005, letter the VDEQ requested "that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shutdown of the facility." (emphasis in original)

In response to the letter from the VDEQ, Mirant chose to shut down all five of the generating units at the Plant on August 24, 2005.

On August 24, 2005, the D.C. Public Service Commission filed an Emergency Petition and Complaint with DOE that requested DOE to issue an emergency order directing Mirant to continue operation of the Plant in order to prevent the risk of a blackout in the Central D.C. area (DCPSC 2005). The Commission also requested that the Federal Energy Regulatory Commission (FERC) issue a similar order under Sections 207 and 309 of the FPA.

Mirant then completed a refined computer modeling study using more realistic scenarios that indicated that the Plant could operate, in a limited fashion, within air quality standards. Thus, on September 21, 2005, Mirant restarted only Unit 1 at the Plant. From that date until the DOE Order was issued, Mirant operated that unit on an 8-8-8 basis – that is, in any given 24-hour period, the unit ran for up to eight hours at its maximum level, ran for eight hours at its minimum level, and did not run for eight hours. Mirant also experimented during this period with using trona (i.e., sodium sesquicarbonate, a naturally occurring substance similar to baking soda) or low-sulfur Colombian coal[3], alone or in combination, to control SO_2 emissions in order to determine if such changes would allow simultaneous operation of more than one unit without causing NAAQS exceedances.

---

[2] (...continued)
when aerodynamic turbulence induced by nearby structures causes pollutants from an elevated source (such as a smokestack) to be mixed rapidly towards the ground resulting in higher ground-level concentrations of pollutants."

[3] During its experiments with low-sulfur coal from Colombia, Mirant determined that the higher moisture content in this type of coal created multiple operational problems. For example, the Plant was unable to dry the coal sufficiently for the coal pulverizers to maintain adequate throughput rates, and the moisture resulted in reduced efficiency of both the combustion and the heat transfer processes. For these reasons after its initial test of Colombian coal, Mirant decided not to use it any further.

After receiving the Commission's petition, DOE conducted an independent examination of the electricity reliability situation in the Central D.C. area and analyzed the Plant's role in ensuring a reliable supply of electricity to that area (Kirby and Kueck 2005). DOE also consulted with Federal and state officials responsible for environmental compliance (e.g., EPA shared information with DOE regarding NAAQS modeled results and other environmental issues at the Plant) and private entities responsible for electricity transmission. DOE's investigation found that the Plant must be available to run when one of the 230-kV lines is out of service in order to maintain a minimally reliable electric power system, because outage of the remaining line could result in a blackout of the Central D.C. area. DOE's investigation also found that the Plant should be operated in such a way as to minimize the amount of time needed to bring it into full operation to be better able to meet electric reliability needs quickly whenever one of the two 230-kV transmission lines was unexpectedly removed from service.

After DOE's investigation, on December 20, 2005, the Secretary issued the Order stating:

> I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

DOE's Order directed Mirant to generate electricity at the Plant under certain, limited circumstances and to do so in such a way as to minimize adverse environmental impacts. The Order required Mirant to (1) operate the Plant to produce the amount of power (up to its full capabilities) needed to meet demand in the Central D.C. area during any period in which one or both of the 230-kV lines serving the Central D.C. area were out of service and (2) in situations when both lines are functioning, keep as many generating units in operation and take all other measures to reduce the start-up time of units not in operation, without regard to cost and without causing or significantly contributing to any exceedance of the NAAQS, in order to provide electrical reliability to the Central D.C. area. The Order also required Mirant to submit a plan to DOE within ten days indicating how it would comply with the Order. (See Appendix A for the full text of the Order.)

On December 30, 2005, as required by the DOE Order, Mirant submitted a plan describing how it would comply with the Order. The plan outlined a proposed temporary phase and two options for a proposed intermediate phase: Option A and Option B. All proposals included the use of trona and/or low-sulfur coal to manage air emissions. Mirant stated in its compliance plan that "Option A results in no modeled NAAQS exceedances." Mirant also stated

that "Option B offers dramatically better reliability than Option A, but results in a marginal computer-modeled exceedance of the 24-hour NAAQS for [SO_2], although the 3-hour and annual NAAQS for SO_2 are met. Moreover, that exceedance was modeled to occur infrequently in the course of a year and only on the top floor balconies and the roof of the Marina Towers condominium..." After reviewing Mirant's compliance plan, DOE instructed Mirant on January 4, 2006, to "immediately take the necessary steps to implement Option A." Between January and May, the Department continued to weigh other options that were available to Mirant to comply with the DOE Order.

On June 1, 2006, Mirant entered into an Administrative Compliance Order (ACO) with EPA regarding operation of the Plant. (See Appendix B.) On June 2, 2006, DOE concluded that operation of the Plant under Option A did not provide an adequate level of electric reliability to the Central D.C. area and that operation of the Plant pursuant to the ACO was necessary to assure an adequate level of electric reliability to the Central D.C. area. Mirant has since that time operated the Plant in accord with those instructions from DOE. Since June 2, 2006, the operation of the Plant under the Order thus followed the scheme summarized in the following paragraphs. (See Section 4.1 for details.) The ACO will expire one year after it was issued, on June 1, 2007.

During "non-line outage situations" the operation of the Plant must follow the ACO, under which Mirant is to "keep as many units in operation," and "take all other measures to reduce start-up time of units not in operation, for the purpose of providing electricity reliability so long as such operations are in accordance with paragraph B of Part IV of the ACO." Among other things, paragraph B authorizes operation in accordance with "daily predictive modeling." Under daily predictive modeling, the Plant operators acquire the appropriate weather forecast for the next day and use that forecast, along with their planned operating parameters, as inputs to conduct a computer modeling run for the following day's planned operation. If the modeling results indicate that operating the Plant under those conditions would not cause a modeled NAAQS exceedance for 3-hr and 24-hr average SO_2 and PM_{10}, the operators may run the Plant on that day using those parameters. If the modeling results indicate that operation of the Plant would cause an exceedance of these NAAQS, the operators adjust their planned operating parameters until the modeling results indicate compliance with the NAAQS. The operators may then operate the Plant using those parameters. Thus, under this scenario the Plant can operate on any one day up to the maximum level allowed by the preceding day's weather forecast.

The ACO requires Mirant to maintain alarms that alert the Plant operators if monitored average concentrations reach 80% of the standards for SO_2, including the annual SO_2 standard. In addition, the ACO requires Mirant to install and operate six new SO_2 ambient monitoring stations in the vicinity where elevated pollutant concentrations have been predicted and to conduct actual monitoring of ambient SO_2 concentrations.

During "line outage situations," the ACO places environmental requirements on Mirant in addition to the requirements of the DOE Order. It requires Mirant to "take all reasonable steps to limit the emissions of PM_{10}, NO_x and SO_2 from each boiler, including operating only the number of units required to meet PJM's directive and optimizing its use of trona injection to

minimize SO_2 emissions." Further, the ACO requires that Mirant achieve "80% reduction of SO_2 emissions unless: 1) Mirant demonstrates ... that 80% reduction is not necessary to achieve compliance with the NAAQS; or 2) Mirant demonstrates that 80% reduction is not logistically feasible because of such factors as the quantity of available trona and the predicted duration of the outage." If Mirant demonstrates that 80% removal is not logistically feasible, it is required to submit a plan to EPA for optimizing its use of trona.

On September 28, 2006, DOE issued an extension of the Order, including all of its terms and conditions, until 12:01 am on December 1, 2006.

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
2004		
September 23	Effective date of Order by Consent between VDEQ and Mirant	
2005		
until August 20		Historical operations; ***Pre-shutdown mode for this SEA***
August 19		Mirant submitted emissions modeling study to VDEQ
August 19	VDEQ requested Mirant to immediately undertake actions to protect human health and environment around the Plant	
August 21		Output at Plant reduced to lowest feasible level from all five units
August 24		Operations at the Plant ceased
August 24	D.C. Public Service Commission filed emergency petition and complaint with DOE and FERC	
September 21		Unit 1 (one of the two load-following or cycling units) restarted on an 8-8-8 basis[3]
September 21 - November 11		Unit 1 operated on an 8-8-8 basis

[3] That is, in any given 24-hour period, the unit ran for up to eight hours at power levels up to its maximum level of 88 MW, ran for eight hours at its minimum level of 35 MW, and did not run for eight hours.

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
November 11 - November 23		Unit 1 operated on an 8-8-8 basis with trona testing
November 24 - December 14		Unit 1 operated on an 8-8-8 basis with Colombian coal testing, but without trona
December 15 - December 20		Unit 1 operated on an 8-8-8 basis with Colombian coal and trona testing; ***Pre-Order mode for this SEA***
December 20	DOE consulted with CEQ	
December 20	The Secretary of Energy issued emergency order requiring Mirant to operate the Plant to assure a reliable supply of electricity to central Washington, D.C.	
December 21- December 23		Plant operated as during December 15 - December 20 period
December 22	DOE consulted with CEQ	
December 24		No data available on Plant operations
December 25 - December 31		Unit 1 operated without using low sulfur coal or trona
December 30		Mirant submitted its compliance plan (also known as the Operating Plan) to DOE identifying two options, A and B
2006		
January 1		No data available on Plant operations
January 2 -3		Unit 1 operated without using low sulfur coal or trona
January 4	DOE instructed Mirant to implement proposed Option A in compliance plan	Plant began to operate under conditions in Option A in compliance plan; Plant continued to operate under Option A until June 2 except during transmission line outages (indicated below).

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
January 6	PJM specified that it was necessary for Mirant to operate the Plant to meet entire Central D.C. load during transmission line outages Pepco proposed for January 7 - 19 and 22 - 27 for maintenance.	
January 7 - 19		Plant operated to meet entire Central D.C. load during line maintenance.
January 13	DOE consulted with CEQ	
January 17	DOE consulted with CEQ	
January 20	DOE issued *Federal Register* notice describing its emergency action and requesting comments on scope of the SEA.	
January 21		A second trona unit became operational
January 21 - 28		Plant operated to meet entire Central D.C. load during line maintenance.
February 21	End of comment period on *Federal Register* notice	
March 6	Pepco receives permission from the D.C. Public Service Commission to construct two new 230-kV lines into the D.C. area and two new 69-kV lines to serve the Blue Plains Wastewater Treatment Plant	
March 20		Third trona unit became operational
March	U.S. Department of Health's Agency for Toxic Substances and Disease Registry began a review of the existing air quality and other environmental data related to the Plant, as requested by the Director of the Alexandria Health Department.	
May 31		All five trona units operational
June 1	EPA issued an ACO to Mirant	
June 2	DOE instructed Mirant to comply with the ACO with EPA	

Table 1.3-1. Chronology of major actions and events related to the Plant

Date	Agencies and other companies	Mirant; Potomac River Generating Station
June 20		Operation began in accordance with daily predictive modeling
July 15	Pepco places two newly constructed 69-kV lines into service at the Blue Plains Wastewater Treatment Plant	
September 28	The Secretary of Energy extended emergency order for two months	
October 1	DOE Order was scheduled to expire at 12:01 am	
November 27 - December 11	Pepco plans transmission line outage for repairs	Full Plant generation will be required to meet central D.C. predicted load because of Pepco line repairs.
December 1	Extension to DOE Order expires at 12:01 am	
2007		
February 19 - March 5	Pepco plans transmission line outage for upgrades	Full Plant generation will be required to meet Central D.C. predicted load because of Pepco line upgrades.
May 2 - 15	Pepco plans transmission line outage for upgrades	Full Plant generation will be required to meet Central D.C. predicted load because of Pepco line upgrades.
May 21 - June 15	Pepco plans transmission line outage for upgrades	Full Plant generation will be required to meet Central D.C. predicted load because of Pepco line upgrades.
June 1	The ACO expires.	
late June	Pepco plans to have two new 230-kV transmission lines in service	.
Fall		Mirant plans to take units out of service to reconfigure the exhaust stacks.

1.4 National Environmental Policy Act (NEPA) Process

Major Federal actions significantly affecting the human environment generally call for DOE to prepare an environmental impact statement (EIS) before taking the action to analyze

impacts in compliance with NEPA. However, in emergency situations, pursuant to 40 CFR 1506.11, the CEQ's NEPA regulations provide that agencies consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing an EIS. DOE consulted with CEQ on December 20, 2005, December 22, 2005, January 13, 2006, and January 17, 2006, on a plan for alternative NEPA arrangements. Under this plan (71 FR 3279, January 20, 2006) DOE agreed to:

- Prepare a SEA to examine the potential impacts resulting from issuance of the Order and describe further DOE decision-making regarding reasonable future alternatives;
- Provide opportunities for public involvement;
- Continue to consult with EPA and the VDEQ concerning information on emissions, modeling results, potential mitigation measures, and any changes in the operation of the Plant; and
- Identify in the SEA steps that could be taken to mitigate any impacts from the DOE Order.

Consistent with the consultations with CEQ, DOE has prepared this SEA.

1.5 Public Involvement

As described above, on January 20, 2006, DOE published a *Federal Register* notice (71 FR 3279) (Appendix C) in which DOE described the action it had taken under the Order and reported its discussions with CEQ and its agreement to issue an SEA as part of its alternative arrangements for NEPA compliance.

DOE also used that *Federal Register* notice to request public comments on the information in the notice, as well as on issues to be addressed in the SEA. The comment period closed on February 21, 2006. DOE received comments from the following organizations: the Mount Vernon group and the Virginia Chapter of the Sierra Club; the Southern Environmental Law Center on behalf of itself and the American Lung Association of Virginia ; the City of Alexandria; and the Institute for Public Representation on behalf of the Potomac Riverkeeper, Inc., the Patuxent Riverkeeper, and the Anacostia Riverkeeper at Earth Conservation Corps. These comments are posted on the DOE website described below. Commentors identified many of the same issues that DOE had determined should be covered in the SEA. Section 1.6 describes where these issues are addressed in this document.

DOE maintains a website containing information (under DOE Docket EO-05-01) about the D.C. Public Service Commission Petition, its proceedings, and the DOE Order itself: http://www.oe.energy.gov/permitting/372.htm. This website also provides links to correspondence related to the petition and the Order, as well as the *Federal Register* notice and the comments received on that notice.

1.6 Scope of the Analysis

Based on its own evaluation of potential impacts and the concerns expressed by commentors, DOE has analyzed the below effects of Plant operations under the Order in the indicated sections of this SEA. Cumulative effects are discussed as appropriate in each section as described at the beginning of Section 4.3.

- Effects of any increased *air emissions* (Section 4.3.1);
- *Health* effects on Plant workers and the public of any increased air pollution; commentors on the DOE *Federal Register* notice expressed particular concern about impacts of increased particulate emissions, especially particulate matter smaller than 2.5 microns ($PM_{2.5}$), and of increased emissions of trace metals and hazardous air pollutants (especially arsenic, beryllium, lead, chromium, cadmium, nickel, and mercury) (Section 4.3.2);
- *Water quality* (Section 4.3.3) and *ecological* (Section 4.3.4) effects due to changes in Plant water use and releases or any increased deposition of air pollutants on soil and terrestrial communities, water bodies, and watersheds; commentors on the DOE *Federal Register* notice expressed concern about the potential for any increased emissions of SO_2 and NO_x to contribute to acid rain, nutrient loading to aquatic systems, and deposition of heavy metals, and the subsequent impacts on the aquatic resources of the Chesapeake Bay and several of its tributaries, specifically the Potomac, Anacostia, and Patuxent rivers;
- *Waste management* impacts (Section 4.3.5), particularly impacts of trona utilization, which commentors on the DOE *Federal Register* notice identified as a concern;
- *Transportation impacts* from increased shipping of coal and trona to the Plant and of wastes away from the Plant (Section 4.3.6); and
- *Environmental justice* impacts (Section 4.3.7).

This SEA also describes alternatives for potential future decision-making that include mitigation measures should the Order be further extended. Among these are several measures suggested by commentors on DOE's *Federal Register* notice on the proposal to prepare this SEA and parties commenting on the Order itself.

Because of the limited nature of the action, certain types of impacts that are usually analyzed in NEPA documents are not addressed.

- Because there would be no construction outside the footprint of the existing facility, no impacts to *land use, soil structure, floodplains,* or *aesthetics* are expected.
- Because only very small amounts of construction and employment are associated with the changed operations at the Plant, no appreciable effects on *social* or *economic resources* are anticipated.

A commentor expressed concern about possible adverse effects of trona utilization on Plant equipment. This concern is not addressed because it is not considered to be an environmental impact.

2. DESCRIPTION OF THE MIRANT POTOMAC RIVER GENERATING STATION

The Plant, which has been operating since 1949, was acquired by Mirant Potomac, Inc in 2000. It is located in Alexandria, Virginia, on the western bank of the Potomac River near the District of Columbia, about 5 miles (8 km) south-southwest of the U.S. Capitol building. (See Figure 2-1.) It is almost directly across the river from the Blue Plains Wastewater Treatment Plant and near Ronald Reagan Washington National Airport. Two National Park Service sites, the George Washington Memorial Parkway, developed both as a memorial to George Washington and to preserve the natural scenery along the Potomac River (NPS undated), and the Mount Vernon Trail (Figure 3.4-1), run past the Mirant Plant.

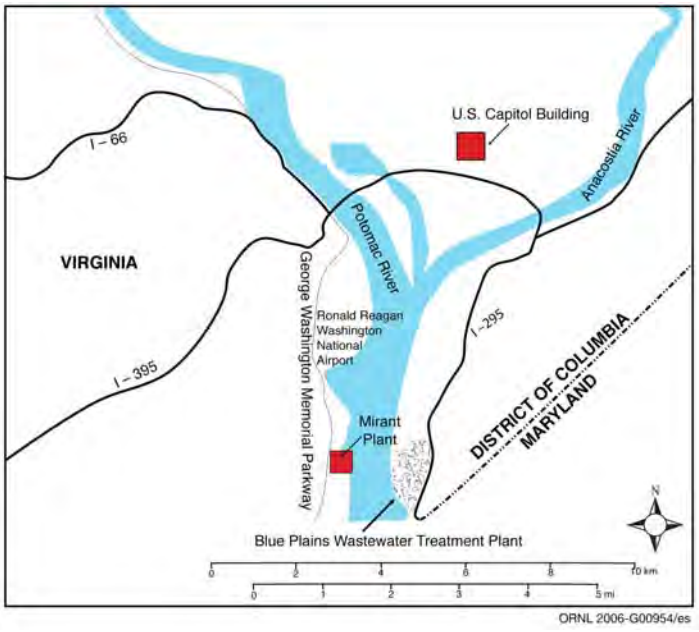


Figure 2-1. The location of the Plant in relation to the central Washington, D.C. area.

The site occupies approximately 28 acres (11 ha) and was relatively remote when the power plant was built. Alexandria has, however, grown up around it, and residential areas are now located immediately adjacent to the Plant. (See Figure 2-2.)

2.1 Site Layout

The footprint of the Mirant Plant is typical for a coal-fired electricity generation facility (see Figure 2.1-1), consisting of a large coal pile and a set of five steam generating boilers. The Plant has five stacks, each 161 ft (49 m) high (Mirant 2006a).

2.2 Plant Equipment and General Operation

The Plant consists of five steam boilers and associated generators with a net generating capacity of 482 megawatts (MW) of electricity for delivery to Central D.C. area customers. Units 1 and 2 are designed to be capable of load-following or cycling; that is, they are capable of changing power levels quickly as demand rises or falls. These units each have a generating capacity of 88 MW (with an operating range of 35 MW to 88 MW). Units 3, 4, and 5 are

designed for baseload operation; that is, they are intended to generate power at a steady rate for extended periods, typically 24 hours per day, and have historically been used more than Units 1 and 2 (Mirant 2006a). Units 3, 4, and 5 each have a generating capacity of 102 MW (with an operating range of 35 MW to 102 MW).

The facility uses oil to pre-heat units during startup and then burns coal. The Plant receives coal by rail car delivered by the CSX Railroad. (See Figure 2.1-1.) The rail cars are unloaded at a dedicated rail siding at the Plant. Typical plant operations involve unloading the rail cars and feeding some coal directly into the boiler building; additional coal is stored on-site in an outdoor coal pile with a capacity of 135,000 tons (122,000 metric tons). The coal storage yard occupies 4 acres (2 ha) and has an average coal-pile height of about 30 ft (9 m). Diesel-fueled bulldozers move the coal around the footprint of the coal pile, and a conveyor system transfers coal from the coal pile into the boiler building. The coal is pulverized in the boiler building and sized for injection into the five boilers. Steam is then piped from the boilers into the turbine building where the generators produce electricity.

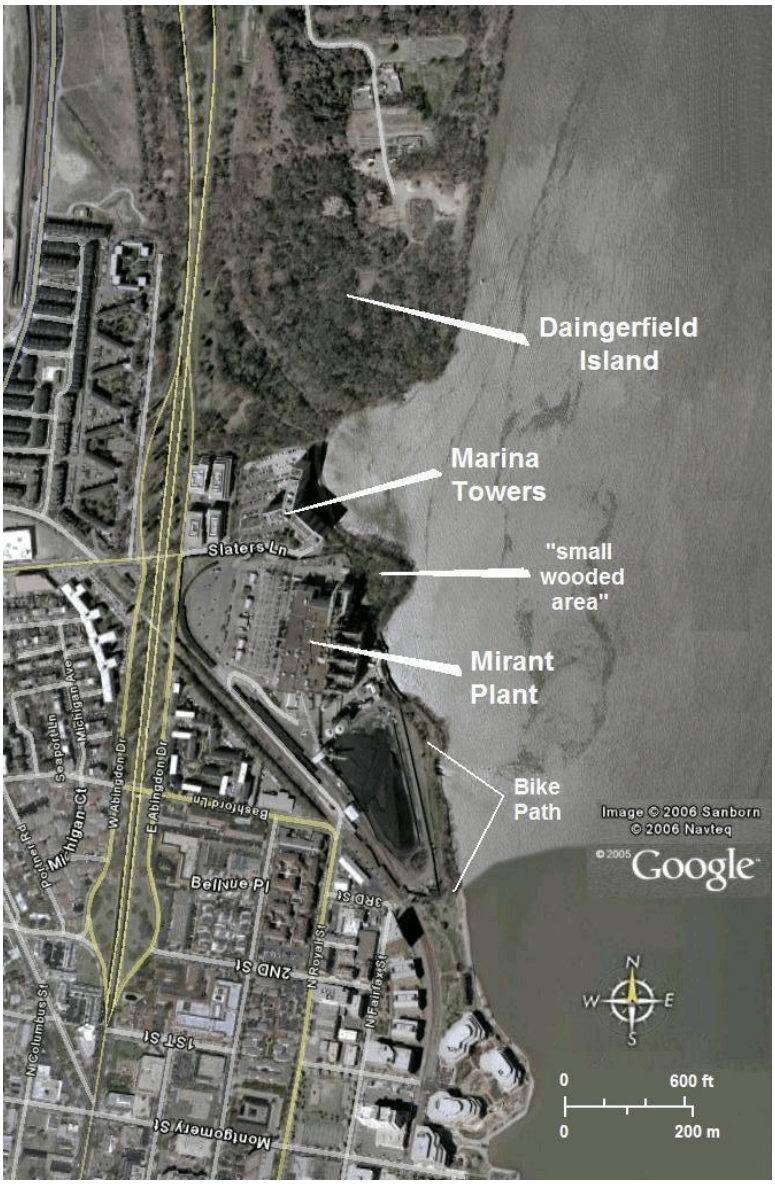


Figure 2-2. Aerial photo showing the Plant and surrounding residences.

Flue gases from each of the five boiler units exhaust to the atmosphere through separate, dedicated stacks. (See Figure 2.1-1.) Pollution abatement equipment at the Plant consists of hot- and cold-side electrostatic precipitators for each boiler unit. These precipitators remove solid particulate matter, called fly ash, from the exhaust gas streams. The fly ash collected by the precipitators is stored in a pair of on-site silos prior to being shipped by covered truck for off-site

disposal. Bottom ash from the boilers is collected and stored in a silo prior to being shipped off-site for beneficial use. (See Section 2.4.3)

The Plant also has trona injection units for each of the five boiler units. Each trona injection unit consists of 8 or 10 injection nozzles in the outlet duct from the boiler economizer to the hot-side precipitator inlet. Each injection unit is capable of injecting trona at a rate of up to 12,000 lb/hour (5,500 kg/hour), which Mirant's study determined to be sufficient to remove 80% of SO_2 from flue gas (Mirant 2006c). At maximum capacity the trona injection units on all five boilers can utilize a total of 25 tons (23 metric tons) of trona per hour to remove about 80% of SO_2 from flue gases. Trona is delivered to the site in 100-ton (91-metric ton) railcars shipped directly from the mine in Green River, Wyoming. Trona is fluidized and transferred pneumatically from the railcars to a 35-ton-capacity (32-metric ton-capacity) trona feed trailer adjacent to each boiler. Trona is transferred pneumatically to the boiler unit outlet duct where it is injected.

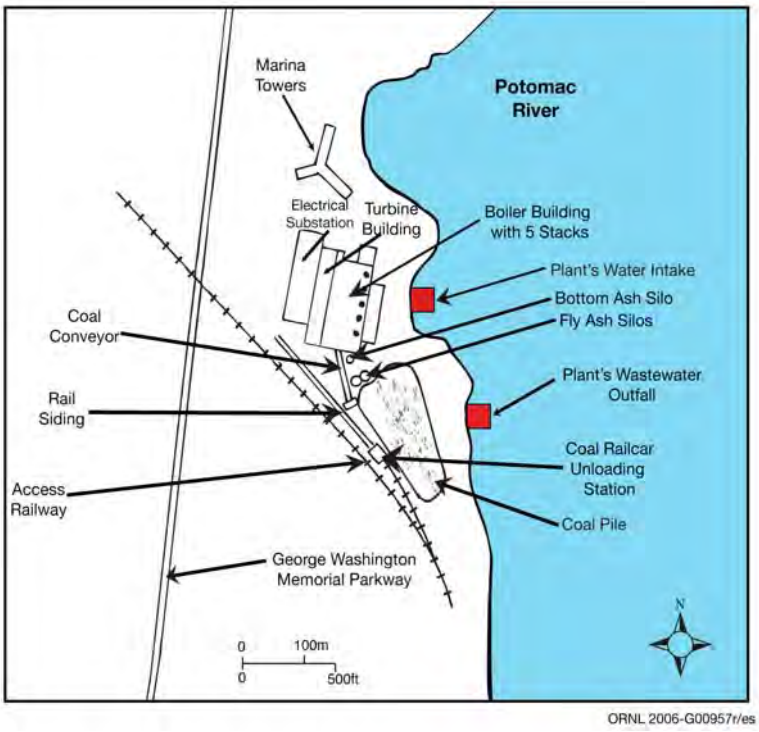


Figure 2.1-1. The site layout of Mirant's Potomac River Generating Station.

The Plant has a once-through cooling water system. Raw water is pumped from the Potomac River through a 1,250-ft^2 (116-m^2) rectangular intake area located on the river bottom along the shoreline, about 10 ft (3 m) below the water surface (Personal communications between D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 12, 2006, and between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). The intake area is made up of 10 intake bays (two for each of the boiler units), each of which is 13.5 ft (4.1 m) long by 9 ft (3 m) wide and equipped with a 30,000-gal/min (about 100 m^3/min) pump (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). Mirant installed new fine-mesh screens on the intakes in July and August 2005. One screen on an intake for Unit 1 is fitted with "fish buckets" for enhanced fish protection. All screens, with or without the enhanced system of fish recovery, facilitate the return of fish to the river south of the power plant intake. After removing debris and suspended solids, the Plant uses this water to cool condensers and auxiliary equipment associated with steam turbines (Mirant 2006b). Major water

treatment equipment includes a clarifier, settling pond, neutralization system, and an oil/water separator.

2.3 Resource Requirements

The Plant primarily uses three resources: coal, trona, and water. Each of these is discussed separately in this section.

In the period prior to August 24, 2005, the Plant typically used an average of about 2,280 tons (2,050 metric tons) of coal per day. Operation at full capacity could require up to 5,150 tons (4,670 metric tons) of coal daily. The Plant normally used central Appalachian coal with a heating value of about 12,000 Btu/lb, an ash content of about 14%, a sulfur content of 0.64% by weight, and a carbon content about 67% by weight.

Analyses of coal burned in 2003 indicates that the average mercury content was between 0.03 and 0.07 ppm (dry). DOE conservatively assumes that the coal consumed by Mirant contains 0.07 ppm mercury on average, or about 1.4 lb (0.6 kg) mercury per 1,000 tons (910 metric tons) of coal.

The coal data that Mirant provided to DOE did not include concentrations of toxic metals other than mercury. Table 2.3-1 presents some published data on concentrations of seven trace metals in other central Appalachian coals. These analyses provide an approximate indication of levels that may be present in the central Appalachian coal burned by the Plant.

Table 2.3-1. Ranges of values for trace metal concentrations in as-mined samples of Appalachian coals

Trace metal	Reported concentrations (mg/kg)
Arsenic	7 – 23
Cadmium	ND – 0.2
Lead	15 – 24
Selenium	ND – 2.9
Beryllium	1 – 2
Chromium	30 – 63
Nickel	18 – 34

ND = below quantitation limit
Source: Palmer et al. 1997.

Trona consumption is determined by the target for SO_2 removal. Theoretical calculations show that if trona reacted completely with SO_2 in the hot-side precipitator inlet gas, 2.354 parts by weight of trona would be required to react with each part by weight of SO_2 (e.g., 2.345 lb trona per lb of SO_2). However, testing by Mirant found that much larger quantities of trona must be used in order to achieve desired SO_2 removal rates. Addition of trona to the exhaust gas stream at five times the theoretically calculated rate was found to remove 80% of the SO_2 (Mirant 2006c). For typical coal burned at the Plant, removal of 80% of SO_2 would require 0.15 lb of trona per lb of coal burned (1 lb trona per 6.7 lb coal). Because Mirant does not operate the Plant to achieve 80% SO_2 removal most of the time, average trona consumption is about 1 lb for every 8.5 lb of coal consumed (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Water withdrawals from the Potomac River for cooling water and other in-plant uses are estimated to be about 1% higher than discharges (Personal communication between A. Wearmouth and D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006). Therefore, based on discharges (Section 2.4.2), withdrawals are estimated to have averaged somewhat less than 350 million gal/day (1.3 million m^3/day) under pre-shutdown operating conditions (prior to August 24, 2005).

2.4 Waste and Effluents

2.4.1 Air Emissions

The VDEQ approved a Stationary Source Permit to Operate on September 18, 2000, and a Phase II Acid Rain Permit on February 28, 2003. The Stationary Source Permit limits NO_x (as NO_2) emissions to 0.38 lb/MBtu. The EPA judicial consent decree, as amended (EPA 2004, 2006g), requires Mirant to limit Plant total NO_x emissions during the May 1 to September 30 period each year to 1,600 tons (1,500 metric tons) through 2009, among other things. The Acid Rain Permit allocates annual allowances for air emissions of SO_2 during its effective period of January 1, 2003, through December 31, 2007. SO_2 allowances for individual generating units range from 2308 to 3036 tons/year and total 13,344 tons/year for all units combined; in addition, the permit authorizes Mirant to acquire SO_2 allowances from other sources. The Acid Rain permit also limits emissions of NO_x, but the limitation on NO_x is less restrictive than the limit in the Stationary Source Permit.

The coal burned at the Plant averages about 67% by weight carbon. On a day when the Plant consumed 2,280 tons (2,050 metric tons) of coal, as it typically did in the period prior to August 24, 2005, it released about 11 million lb (5,600 tons) of CO_2.

2.4.2 Water Effluents

Plant effluents, including cooling water, boiler blowdown, runoff from the coal pile and fly ash handling areas, and other storm water runoff, are discharged to the Potomac River under National Pollutant Discharge Elimination System (NPDES) permit DC0022004. This permit was last issued for a 5-year duration in 2000 and expired in 2005. Mirant applied for renewal in 2004 (Wearmouth 2004), and the existing permit remains in force while EPA considers the application for renewal (Capacasa 2005). According to the renewal application (Wearmouth 2004), under historical operating conditions discharge under this permit averaged almost 345 million gal/day (1.3 million m^3/day), of which all but about 0.4 million gal/day (1,500 m^3/day) was once-through cooling water.

Boiler blowdown and effluent from treatment (i.e., demineralization) of intake water are treated by sedimentation and neutralization. Before being mixed with other wastewaters, they are monitored (in accordance with permit requirements) for flow rate, pH, total suspended solids, and oil and grease to verify that concentration limits in the permit are met. Ash clarifier system wastewater and runoff from the coal pile and fly ash handling areas are treated by rapid mixing, flocculation, and precipitation. They are monitored for the same set of parameters prior to mixing with other wastewaters. Once-through cooling water and storm water runoff from uncontaminated areas are blended with the treated effluents and discharged without additional treatment. No chlorine or other chemicals are added to the cooling water or used in the Plant's other water processes.

The NPDES permit requires monitoring of flow rate and other parameters at several internal monitoring points and at outfalls. Mirant submits monthly reports with the monitoring data to EPA and the Washington, D.C. Department of Health (Mirant 2006b). The Plant's primary wastewater outfall is subject to permit limits on pH, total residual chlorine, thermal output, and temperature rise in the river. Heat discharge in cooling water is limited to 4,286 MBtu/hr. Temperature rise in the river is limited to 2.8°C above ambient temperature and a maximum temperature of 32.2°C beyond a 1,000-ft (300-m) radius of the discharge point when the ambient river temperature is less than 27.8°C and beyond a 1,600-ft (490-m) radius when the river temperature is warmer than 27.8°C. Mirant conducted temperature surveys in the river in 2001 that confirmed that heat discharge from the Plant does not cause exceedance of these temperature limits, so temperature monitoring in the river is not required (Mirant 2002, NPDES permit document, and personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006).

Table 2.4-1 lists reported concentrations of selected contaminants in the Plant's cooling water intake and in effluent from the outfall that receives cooling water and treated wastewaters from demineralization, boiler blowdown, coal pile runoff, and fly ash handling. The table includes data for many parameters that are not listed in the Plant's NPDES permit. The near-neutral effluent has higher levels of biochemical oxygen demand, suspended solids, nitrate and nitrite, sulfate, aluminum, iron, manganese, copper, and fecal coliform bacteria than the intake

water, while loadings of chemical oxygen demand, total organic carbon, residual chlorine, phosphorus, and phenols are decreased in the effluent compared with the intake water.

Table 2.4-1. Water quality of Plant intake water and cooling water effluent

Contaminant	Intake Concentration (mg/L)	Effluent Concentration (mg/L, except as indicated)
Biochemical oxygen demand	9.6	14
Chemical oxygen demand	22	21
Total organic carbon	4.7	4.3
Total suspended solids	24	39
Fecal coliform bacteria	27	110
pH (pH units)	—	7.6
Chlorine, total residual	0.15	0.05
Fluoride	0.20	0.12
Nitrate-Nitrite as N	1.1	1.2
Nitrogen, total organic	ND	ND
Phosphorus	0.076	0.060
Sulfate	33	37
Aluminum	0.75	1.4
Iron	0.86	1.5
Manganese	0.11	0.13
Copper	ND	0.013
Zinc	0.023	0.023
Phenols, total	0.015	0.014

ND = Not detected
— = Not reported
Source: Wearmouth 2004; These values are from a single set of measurements and may not be representative.

2.4.3 Solid Wastes

The Plant's principal solid wastes are fly ash collected from exhaust gases and bottom ash from the boilers. (See Section 2.2.) Under pre-shutdown operating conditions prior to August 24, 2005, reported fly ash generation totaled about 14,200 tons/month (12,900 metric tons/month), equivalent to about 20% of coal consumption. Bottom ash generation equals about 25% of the fly ash generation (Personal communications between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006; and between D.

Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 12, 2006, and July 14, 2006).

Fly ash is sent by covered truck to the Brandywine Fly Ash Facility, a landfill located in southeastern Prince George's County, Maryland (Figure 2.4-1), that is owned and operated by Mirant Ash Management LLC and used solely for disposal of coal combustion ash. (See Section 3.5.) Plant fly ash is marketed for beneficial use, primarily for structural fill, but historically its utilization has been very limited (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). The fly ash generated by the Plant under historical operating conditions is a pozzolanic material (that is, when mixed with water it "sets," like cement), but its unburned carbon content is too high to permit its use as a cement substitute (TFHRC undated). Bottom ash from the Plant is used or sold for purposes such as road fill.

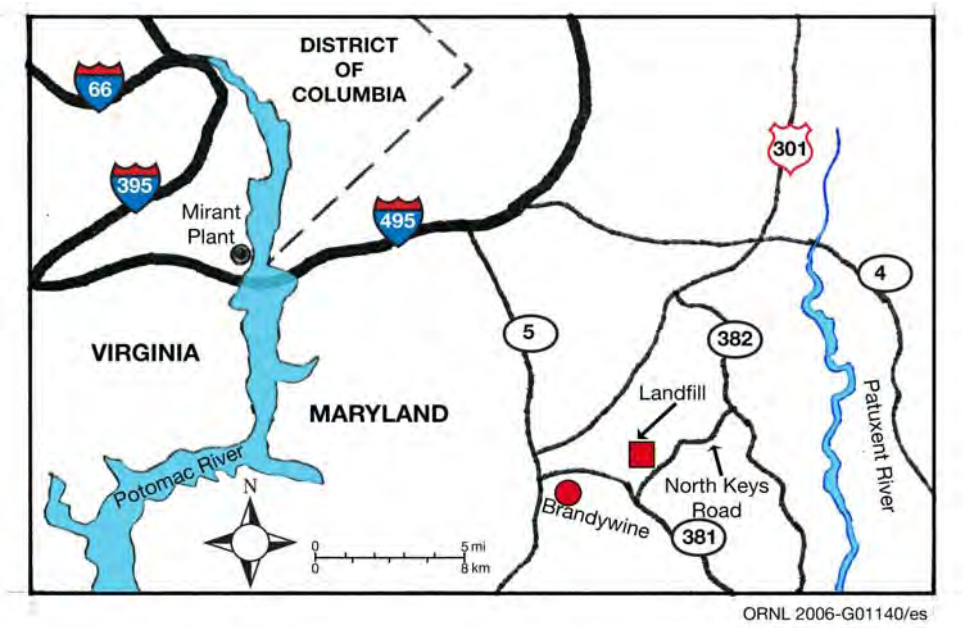


Figure 2.4-1. The location of and access routes to the Brandywine Fly Ash Facility used for disposal of solid wastes from the Plant.
Note: Mataponi Creek (not shown on the map) originates near Brandywine and flows east-northeast to the Patuxent River.

2.5 Changes to the Plant Since the DOE Order

Mirant has made several changes inside the existing Plant buildings since the DOE Order. The most important of these is the addition of trona injection units to all five boilers. Mirant has also made provision to withdraw trona from rail cars and transfer it to storage

containers inside the building. Several measures to control fugitive dust (for example, improved ash-loading systems for the two fly ash silos) were implemented during 2005 and 2006 in response to a 2004 EPA judicial consent decree (EPA 2004)that required Mirant to take actions to reduce fugitive particulate emissions. None of these changes included new construction or other disturbances at the Plant site.

Mirant is planning to merge the boiler exhaust gases from Units 1 and 2 and run the combined exhaust through the stack of Unit 1. Similarly Mirant is planning to merge the boiler exhaust gases from Units 3, 4, and 5 and run them through the stack of Unit 4. Mirant's modeling shows that combining the gas flows from the two units into one stack and from the three other units into another stack produces higher exit velocities and increases plume rise for all emissions into the atmosphere and, thus, lessens the potential for downwash impacts (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Merging unit exhaust gases requires new common ductwork to be installed connecting the individual unit exhaust fan discharges, and installation of new higher capacity fans. This common ductwork will be connected to the existing stack at the existing location at the base of the stack. This common ductwork will be installed inside the existing plant structure and will not be visible from the ground since it will be located in-between the existing precipitator and stacks. There will be no foundations required for this ductwork.

Mirant plans to implement the exhaust system changes during the fall of 2007 (Personal communication between Richard Killian, EPA Region 3, and L.N. McCold, Oak Ridge National Laboratory, October 16, 2006). Each Plant generating unit is expected to have an outage of 7 to 9 weeks in order to remove the existing equipment and install the new equipment.

3. AFFECTED ENVIRONMENT

This section describes the resources and environmental conditions that could be affected by the DOE action. The areal extent of this "affected environment" is not the same for all potentially affected resource areas. Also, because the purpose of this descriptive information is to lay the foundation for evaluating potential environmental impacts of the action, not all resources and geographic areas are described at the same level of detail.

For air quality the extent of the affected environment is very large because air emissions from the Plant are transported within a large region. However, because the potential effects of greatest interest, including the potential for exceedances of ambient air quality standards, are concentrated in a local area very near the Plant, the description and assessment in this document focus primarily on a 36-mi^2 (93-km^2) area within about 3 mi (5 km) of the Plant. Similarly, the area of primary interest for human health and environmental justice is this same 36-mi^2 (93-km^2) area.

For water resources and ecosystems the affected environment consists primarily of the resources directly affected by Plant operations, including the Potomac River, the Plant site, and neighboring lands. However, because atmospheric deposition of contaminants emitted from the Plant to the air contributes to cumulative impacts to water quality and ecosystems in a larger region, the Anacostia River, Patuxent River, Chesapeake Bay, and other land and water areas (including Potomac River tributaries and their watersheds) within about 20 miles (32 km) of the Plant are treated as part of the affected environment for water resources and ecosystems.

For waste management and transportation the affected environment includes the Plant site; the landfill used for disposal of Plant fly ash; the local roads and rail facilities used for access to the Plant and landfill; and resources in the immediate vicinity of these facilities that may be affected by their air, water, or noise emissions.

3.1 Climate and Air Quality

3.1.1 Climate

The Plant is in Alexandria, Virginia, which lies at the western edge of the mid-Atlantic Coastal Plain, about 50 mi (80 km) east of the Blue Ridge Mountains and 35 mi (56 km) west of the Chesapeake Bay, adjacent to the Potomac River. Elevations range from a few feet (about a meter) above sea level to about 400 ft (122 m).

Weather observations in the vicinity have been kept continuously since November 1870. Since June 1941, the official observations have been taken at Ronald Reagan Washington National Airport (National Airport), just north of the Plant.

National Airport is located at the center of a large urban complex. As a result, low temperatures there are higher than those in surrounding areas. In winter low temperatures at the airport are often 10-15°F (6-8°C) higher than in suburban locations. There is less difference between airport and suburban high temperatures. The normal summertime high temperatures range from 85-90°F (30-32°C), and the average winter lows range from 26-32°F (-3 to 0°C). Normal precipitation is distributed rather uniformly throughout the year, ranging, approximately, from 2.7 to 3.9 inches (6.9 to 9.9 cm) per month.

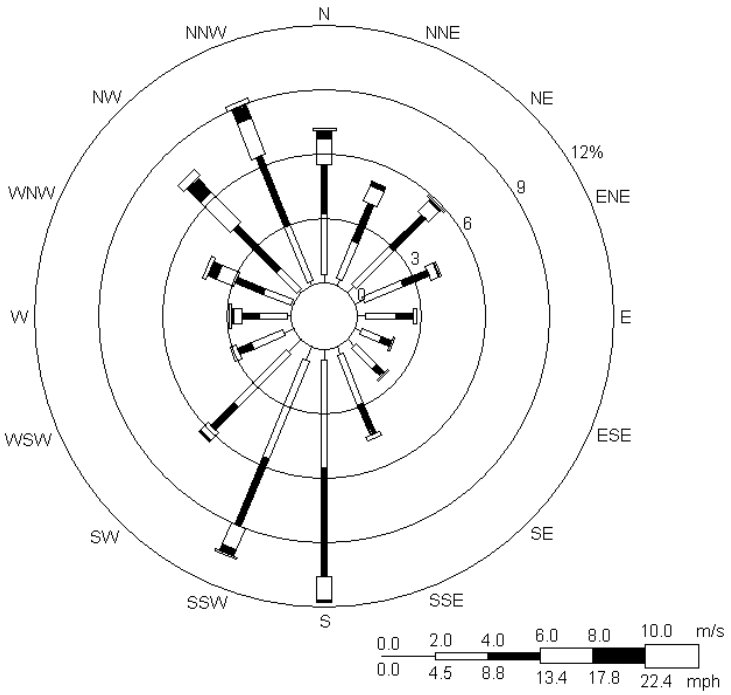


Figure 3.1-1. Wind rose for Ronald Reagan Washington National Airport, 2000-2004 weather data

Thunderstorms can occur at any time but are most frequent during the late spring and summer. The storms are often accompanied by downpours and gusty winds, but are not usually severe. Tornadoes, which occur infrequently, have resulted in significant damage. Severe hailstorms have occurred in the spring. Tropical storms can bring heavy rain, high winds, and flooding, but extensive damage from wind and tidal flooding is rare. Wind gusts of nearly 100 mi (160 km) per hour and rainfall over 7 inches (18 cm) have occurred during the passage of tropical storms.

Normal snowfall during the winter season is 15 inches (38 cm). The average date of the last freezing temperature in the spring is April 1, and the average date for the first freezing temperature in the fall is November 10.

Winds are most often from the south or south-southwest and from the north-northwest (Figure 3.1-1).

3.1.2 Air Quality

Criteria pollutants are defined as those for which National Ambient Air Quality Standards (NAAQS) exist (Table 3.1-1). These pollutants are carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter less than or equal to 10 µm in aerodynamic diameter (designated PM_{10}), particulate matter less than or equal to 2.5 µm in aerodynamic diameter (designated $PM_{2.5}$), and sulfur dioxide (SO_2).

Table 3.1-1. National Ambient Air Quality Standards for criteria pollutants

Pollutant	Averaging period	Concentration
CO	8-hour [a]	9 ppm (10 mg/m^3)
	1-hour [a]	35 ppm (40 mg/m^3)
Lead	Maximum quarterly average	1.5 µg/m^3
NO_2	Annual arithmetic mean	0.053 ppm (100 µg/m^3)
O_3	4th highest 8-hour daily maximum [b]	0.08 ppm (157 µg/m^3)
PM_{10}	Annual arithmetic mean [c]	50 µg/m^3
	24-hour [c]	150 µg/m^3
$PM_{2.5}$	Annual arithmetic mean [d]	15 µg/m^3
	98th percentile 24-hour [d]	65 µg/m^3
SO_2	Annual arithmetic mean	80 µg/m^3 (0.03 ppm)
	24-hour [a]	365 µg/m^3 (0.14 ppm)
	3-hour [a]	1,300 µg/m^3 (0.50 ppm)

[a] Not to be exceeded more than once per year.

[b] The 8-hour standard is met when the 3-year average of the annual 4th highest daily maximum 8-hour O_3 concentration is less than or equal to 0.08 ppm.

[c] The annual PM_{10} standard is attained when the expected annual arithmetic mean concentration is less than or equal to 50 µ/m^3 (3-year average); the 24-hour standard is attained when the expected number of days above 150 µ/m^3 is less than or equal to 1 per year. EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM_{10} standard, effective December 18, 2006.

[d] The annual $PM_{2.5}$ standard is met when the annual average of the quarterly mean $PM_{2.5}$ concentrations is less than or equal to 15 µg/m^3, when averaged over 3 years. If spatial averaging is used, the annual averages from all monitors within the area may be averaged in the calculation of the 3-year mean. The 24-hour standard is met when the 98th percentile value, averaged over 3 years, is less than or equal to 65 µg/m^3. Under new standards published on October 17, 2006, and effective December 18, 2006 (EPA 2006j), the 24-hour standard will be 35 µg/m^3. The state of Virginia has until April 2008 to develop and submit to EPA for approval SIP provisions to implement, maintain, and enforce the new NAAQS for $PM_{2.5}$.

[e] Same as primary standard.

Source: 40 CFR Part 50.

The NAAQS are expressed as concentrations of pollutants in the ambient air; that is, in the outdoor air to which the general public has access [40 CFR 50.1(e)]. Primary NAAQS define levels of air quality that EPA deems necessary, with an adequate margin of safety, to protect human health. Secondary NAAQS are similarly designated to protect human welfare by safeguarding environmental resources (e.g., soils, water, plants, animals) and manufactured materials. States may modify NAAQS to make them more stringent or set standards for additional pollutants. Virginia has adopted the NAAQS as the state standards without modifications.

Attainment status for NAAQS is determined primarily by evaluating data from ambient air quality monitoring stations. The monitoring station nearest to the Plant (AIRS 51-510-0009) is located at the Alexandria Health Department, 517 North Saint Asaph Street, 0.6 mile (0.9 km) south. The station monitors CO, SO_2, NO_2, and O_3. The nearest $PM_{2.5}$ monitoring station (AIRS 51-013-0020) is located at Aurora Hills Visitors Center, 18th and Hays Streets, Arlington County, due west of Ronald Reagan Washington National Airport and 2.7 miles (4.4 km) north-northwest of the Plant. The nearest PM_{10} monitoring station (AIRS 51-059-0018) is located at Mount Vernon Fire Station, 2675 Sherwood Hall Lane, Mount Vernon, 5.7 miles (9.2 km)

south-southwest of the Plant. Because no lead monitoring stations are employed in Virginia, this section does not discuss lead.

Table 3.1-2 summarizes recent air quality data in the vicinity of the Mirant Plant.[4] The city of Alexandria and surrounding Arlington, Fairfax, Loudoun, and Prince William Counties are designated as NAAQS nonattainment areas for $PM_{2.5}$ and the 8-hour O_3 standard (VDEQ 2006a, 2006b).

Table 3.1-2. Ambient air quality in the vicinity of the Plant, 2004

Pollutant	Regulated parameter	Monitored concentration [a]	NAAQS limit
CO [b]	Second highest hour	2.9 ppm	35 ppm (40 mg/m^3)
	Second highest 8-hour average	2.0 ppm	9 ppm (10 mg/m^3)
NO_2 [b]	Annual average	0.024 ppm	0.053 ppm (100 µg/m^3)
O_3 [b]	4th highest 8-hour average	0.080 ppm	0.080 ppm (235 µg/m^3)
PM_{10} [c]	Annual arithmetic average	21 µg/m^3	50 µg/m^3
	Second highest 24-hour average [e]	44 µg/m^3	150 µg/m^3
$PM_{2.5}$ [d]	Annual average	14.4 µg/m^3	15 µg/m^3
	98th percentile 24-hour average	35.7 µg/m^3	65 µg/m^3
SO_2 [b]	Annual average	0.006 ppm	0.03 ppm (80 µg/m^3)
	2nd highest 24-hour average	0.021 ppm	0.14 ppm (365 µg/m^3)
	2nd highest 3-hour average	0.054 ppm	0.50 ppm (1,300 µg/m^3)

[a] *Source:* VDEQ 2005a (Just before publication of this document, Virginia released ambient air monitoring data for 2005 [VDEQ 2006c]. The updated background levels vary only slightly from the 2004 values reported and used here.)
[b] Measured at Alexandria Health Department (AIRS 51-510-0009).
[c] Measured at Mt. Vernon Fire Station (AIRS 51-059-0018).
[d] Measured at Aurora Hills Visitors Center (AIRS 51-013-0020).
[e] EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM_{10} standard, effective December 18, 2006.

Contaminants other than the criteria pollutants are present in the atmosphere in varying amounts that depend on the magnitude and characteristics of the sources, the distance from each source, and the residence time of each pollutant in the atmosphere. In the ambient air many of these pollutants are present in extremely small concentrations, requiring expensive state-of the art equipment for detection and measurement. Hazardous air pollutants are regulated at emission sources based on the National Emissions Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63); measurements of existing ambient air concentrations for many such pollutants are, at best, sporadic.

[4] While additional air quality monitoring stations are located in Maryland and the District of Columbia, the monitoring station for each pollutant nearest the Plant is found in Virginia. (See Metropolitan Washington Council of Governments 2005 and VDEQ 2005a.)

3.2 Human Health

There is a well established association between exposure to outdoor air pollution and a broad variety of health effects, both acute and chronic. These health effects range from simple irritation such as burning eyes to premature death. The principal air pollutants generated by fossil fuel combustion that are associated with these health effects are PM, SO_2, and NO_x (WHO 2000). U.S. ambient air quality standards have been set at levels above background. For example, while the background concentration of SO_2 in the U.S. is about 1 $\mu g/m^3$, the NAAQS for annual-average SO_2 concentration is 80 $\mu g/m^3$. However, human health effects have been reported for concentrations below NAAQS levels for both PM and SO_2 (Dockery et al. 1993).

For the purposes of this SEA DOE has analyzed premature adult (age 30 and older) mortality as a useful indicator for health effects associated with air pollution because background mortality rates are readily obtainable, thereby strengthening the estimates, and the association between air pollution and mortality has well documented exposure response functions. The most recently available all-cause, all-age death rate for the area near the Plant is 7.5 deaths per year per 1000 population, as obtained from the Virginia Department of Health (2004). The most recent all-cause adult (age 30 and older) death rate in the region is 13 deaths per year per 1000 population.

3.3 Water Resources and Water Quality

Water resources potentially affected by Plant operations include the Potomac River and the Patuxent River, as well as the Chesapeake Bay, which is the destination for both of those rivers. The Potomac River supplies water to and receives effluent discharges from the Plant, and the watersheds of the Potomac and Patuxent Rivers include the land areas where air pollutants emitted from the Plant are most likely to be deposited. In addition, effluents from the landfill serving the Plant are discharged to Mataponi Creek, which is in the Patuxent River watershed. The Anacostia River and Rock Creek, which are tributaries to the Potomac located near the Plant, are also specifically discussed in this section.

3.3.1 Physical Setting and Hydrology

The Plant is situated in the Atlantic Coastal Plain physiographic province, in the watershed of Chesapeake Bay (Figures 3.3-1 and 3.3-2). Chesapeake Bay and its major tributaries, including the Potomac and Patuxent rivers, are “drowned river valleys.” That is, they are river valleys that were partially inundated by sea water when sea level rose following the end of the last Pleistocene glaciation. The Potomac, Patuxent, and other major streams in the region arise in upland areas and flow as fresh-water streams to the fall line near the edge of the

coastal plain. Below the fall line, the streams are considered to be estuaries, since their flow is modified by the influence of ocean tides. In the estuarine section of a stream, fresh water mixes with salt water in increasing proportions as the stream flows toward the sea. The effects of tides shelter the waters of these estuaries from the full effects of river currents, while river-valley geometry and stream flow shelter them from the full energy of ocean waves. Because they are sheltered from the flushing actions of both stream flow and ocean waves, water remains in these estuaries for a long time. Thus, pollutants discharged into an estuary remain there much longer than they would in an upland stream or in the open ocean. At the same time the sheltered waters of estuaries support exceptionally productive ecosystems. (See Section 3.4.)

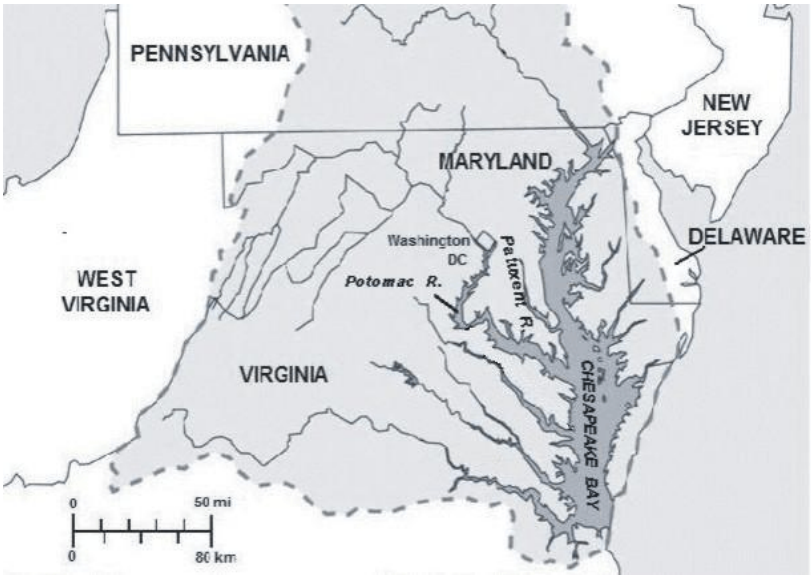


Figure 3.3-1. The Chesapeake Bay watershed includes the Patuxent and Potomac rivers.

3.3.1.1 Potomac River

The Plant is located next to the Potomac River, which flows from the Appalachian mountains to Chesapeake Bay, draining a 14,670-mi^2 (38,000-km^2) watershed in Maryland, Virginia, West Virginia, Pennsylvania, and the District of Columbia

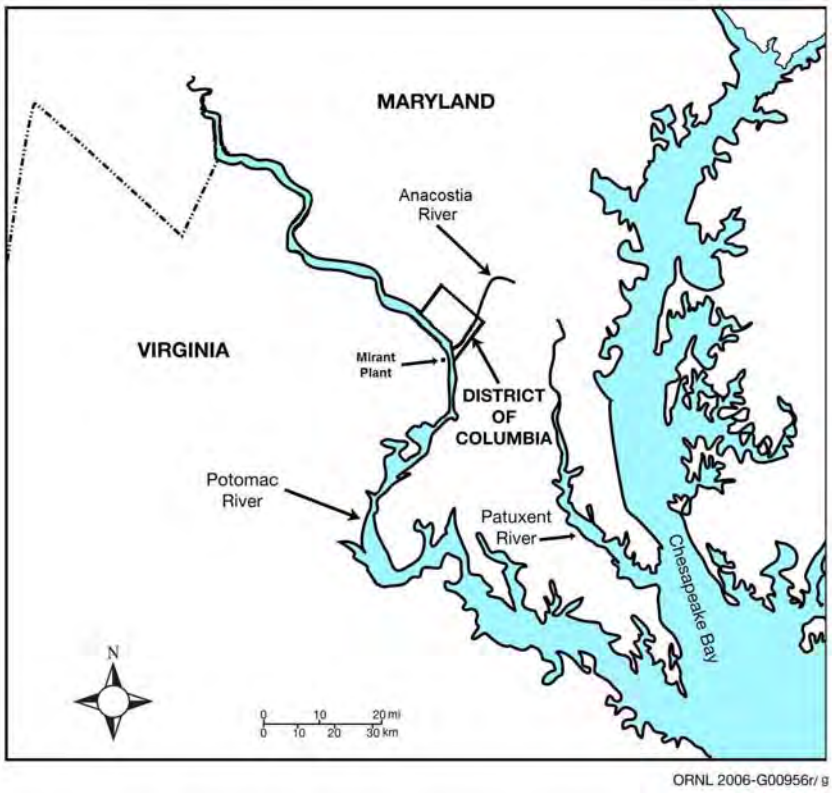


Figure 3.3-2. The Chesapeake Bay watershed near the Plant includes the Potomac, Patuxent, and Anacostia rivers.

(EPA 2000; Wilderness Society undated). The river is tidally influenced for about 110 miles (180 km) from the fall line at Little Falls, Maryland (located a short distance upstream from the District of Columbia border, about 11 miles [18 km] upstream from the Plant), to its mouth at Chesapeake Bay (EPA 2000).

While the entire tidally influenced reach of the river is an estuary, it is classified in three distinct hydrographic regimes: tidal river, transition zone, and mesohaline estuary. Adjacent to the Plant the Potomac is a tidal river with fresh water (salinity less than 500 mg/L) and a net seaward flow direction throughout the water column (EPA 2000). The transition zone begins approximately 38 miles (61 km) downstream from the fall line, about 27 miles (43 km) downstream from the Plant. The transition zone is about 22 miles (35 km) long and is characterized by variable salinity (from 500 to 10,000 mg/L) and significant mixing of fresh water with salt water from Chesapeake Bay. The lower 50 miles (80 km) of the river are classified as a mesohaline estuary with salinity varying from 5,000 to 18,000 mg/L (EPA 2000). Near the Plant the river channel has been extensively modified by past dredging and spoil disposal.

Average stream flow in the Potomac River at the fall line (above the zone of tidal influence) over the 50-year period 1931-1981 was 11,406 ft^3/sec (7.4 billion gal/day or 28 million m^3/day) (EPA 2000). Seasonally, flow is highest in the spring (February through May) and lowest in the late summer (July through September). September is the month with the lowest average flow, 4,126 ft^3/sec (2.7 billion gal/day or 10 million m^3/day). The long-term mean 7-day, 10-year low flow at the fall line is 628 ft^3/sec (406 million gal/day or 1.54 million m^3/day). The District of Columbia and some other area jurisdictions obtain public water supplies from the Potomac above the fall line.

3.3.1.2 Anacostia River

The Anacostia River is a tributary to the Potomac River that enters the Potomac approximately 4 miles (6 km) upstream from the Plant. The extensively urbanized Anacostia watershed encompasses 176 mi^2 (456 km^2) in Montgomery and Prince George's County, Maryland, and the District of Columbia. The Anacostia is a tidal river for its lower 8.4 miles (13.5 km). Flow in the tidal reach is described as sluggish; this reach has an average water residence time of 30 to 35 days. Average flow into the tidal reach from free-flowing tributaries and reaches is approximately 138 ft^3/sec (89 million gal/day or 338,000 m^3/day) (Anacostia Watershed Network 2006).

3.3.1.3 Rock Creek

Rock Creek (Figure 3.3-3) is a tributary to the Potomac River that enters the river several miles upstream from the Plant. Approximately 80% of its watershed is in Montgomery County, Maryland, with the remainder in Washington, D.C. (MDOE 2006). The nontidal portions of the

creek occur mainly within Maryland and cover about 60 mi^2 (155 km^2); the tidal portion is mainly within D.C.

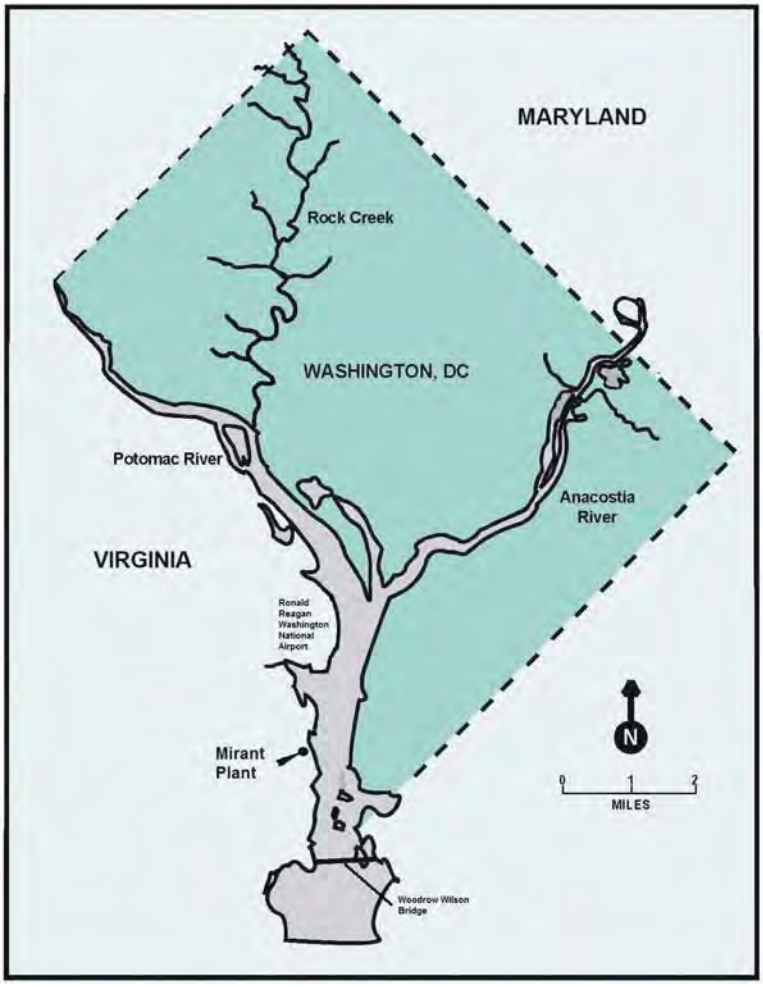


Figure 3.3-3. Location of features mentioned in the text.

3.3.1.4 Patuxent River

The Patuxent River watershed is immediately east of the Potomac River watershed in the Maryland counties of Anne Arundel, Calvert, Charles, Howard, Montgomery, Prince George's, and St. Mary's (Maryland DNR undated-a). The drainage divide between the Potomac and Patuxent watersheds is about 10 miles (16 km) east of the Plant. Only about 40% of the 849-mi^2 (220-km^2) Patuxent River watershed contributes to the river's flow above the fall line; the remainder of the watershed drains directly to the river's estuary, which has a water surface area of about 49 mi^2 (127 km^2) (Hagy and Kemp 2002). Total stream flow to the Patuxent estuary averages about 728 ft^3/sec (470 million gal/day or 1.78 million m^3/day) (Boynton and Swaney 1998). Fresh water residence time in the estuary typically varies between 50 and 80 days (Hagy and Kemp 2002).

Mataponi Creek, the Patuxent River tributary that receives discharges from the Mirant landfill (Section 3.5), originates in the upland near Brandywine, Maryland (Figure 2.4.1) and flows east-northeast toward the Patuxent River, entering the fresh water tidal reach of the river at a location about 9 miles (14 km) northeast of Brandywine. No stream flow or water quality data have been located for Mataponi Creek.

3.3.1.5 Chesapeake Bay

The Chesapeake Bay is the largest estuary in the United States, about 200 miles (320 km) in length, with a surface area of about 4,400 mi^2 (11,000 km^2) (including the estuarine reaches of its major tributaries) and a watershed of about 63,000 mi^2 (164,000 km^2), including the District

of Columbia and parts of the states of Delaware, Maryland, New York, Pennsylvania, Virginia, and West Virginia (Figure 3.3-1). The Chesapeake Bay is the destination of all waters in the region. The Potomac and Patuxent rivers contribute about 15% and 1% of the stream flow into the Bay, respectively (Boynton and Swaney 1998). Average water depth in the Bay is about 22 ft (7 m).

3.3.2 Water Quality

Important water quality concerns for all potentially affected surface waters include the potential for excessive sedimentation and depletion of dissolved oxygen. Dissolved-oxygen depletion is attributable to excessive loadings of organic materials and nutrients. The long water residence times and poor flushing that are typical of estuaries increase the susceptibility of estuaries to pollution problems. Effects on aquatic ecosystems are the principal focus of concern regarding water quality in these waters, as discussed further in Section 3.4. Public water supplies are obtained from rivers and reservoirs above the fall line; tidal waters generally do not supply water for human consumption. Information about water quality conditions in specific surface water bodies is presented below.

3.3.2.1 Potomac River

Water quality in the tidally influenced sections of the Potomac River is controlled primarily by the mixing of fresh water from upland streams and salt water from Chesapeake Bay, resulting in variable salinity. In the vicinity of the Plant fresh water predominates over salt water, and total dissolved solids are less than 500 mg/L. Table 2.4-1 includes additional data on the quality of river water at the Plant's water intake.

Due to their volume, effluent discharges from the Plant and the Blue Plains Wastewater Treatment Plant have the potential to be important influences on Potomac River water quality near the Plant. Data on the quality of effluents from the Plant are provided in Table 2.4-1.

The Blue Plains Wastewater Treatment Plant, owned and operated by the District of Columbia Water and Sewer Authority, is directly across the Potomac River from the Plant. (See Figure 2-1.) This facility provides wastewater treatment services for the District of Columbia and portions of Montgomery and Prince George's Counties, Maryland, and Fairfax and Loudoun Counties, Virginia, with a combined population near 2.2 million. The Blue Plains treatment plant has a rated treatment capacity of 370 million gal/day (1.4 million m^3/day) and a peak wet-weather capacity of 1.076 billion gal/day (4.1 million m^3/day). Operation at the rated capacity delivers a water volume to the river equivalent to 5% of the average flow and more than 90% of the 7-day, 10-year low flow at the fall line. The Blue Plains facility is considered an advanced wastewater treatment facility, providing primary and secondary treatment followed by nitrification-denitrification, effluent filtration, chlorination-dechlorination, and post-treatment aeration (DC WASA 2006). Historically, wastewater effluents discharged at this site caused

severe water quality degradation in the Potomac estuary, including high bacteria levels and low levels of dissolved oxygen. Downstream water quality improved dramatically, however, following implementation of secondary and advanced treatment in the Blue Plains treatment plant (EPA 2000). The NPDES permit for the Blue Plains facility specifies stringent water quality limits for discharges, as indicated in Table 3.3-1.

Table 3.3-1. NPDES-permitted discharge limits for the Blue Plains Wastewater Treatment Plant

Contaminant		Maximum Concentration (mg/L, except as indicated)
Carbonaceous Biochemical Oxygen Demand		5.0
Total Suspended Solids		7.0
Phosphorus, total		0.18
Ammonia Nitrogen (NH_3-N)	May-October	1.0
	November-April	6.5
Dissolved Oxygen		5.0
Chlorine, total residual		0.02
pH (range of values, pH units)		6.0 to 8.5

Source: DC WASA 2006.

Principal water quality concerns for Potomac River tributary streams draining northern Virginia watersheds near the Plant include the effects of urbanization on aquatic habitats, high fecal coliform bacteria counts in some streams, and the need to protect the watersheds of water-supply reservoirs (Northern Virginia Regional Commission undated; Fairfax County Stormwater Planning Division 2001).

3.3.2.2 Anacostia River

Water quality conditions in the free-flowing tributaries of the Anacostia range from excellent to poor, but the tidal reach of the Anacostia River has very poor water quality. Principal water quality issues for the Anacostia watershed include sediment, trash and debris, toxic chemicals, combined sewer and stormwater overflows that discharge directly into the river, and other nonpoint-source pollution (Anacostia Watershed Network 2006). According to EPA (1997), urbanization has altered the Anacostia River and its tributary streams to the point that floods are ten times more frequent, summer flows are much lower, and stream water temperatures are 5 to 10° C higher than under natural conditions. Due to the long water residence time in the tidal reach of the river, this reach has been described as “a very efficient pollutant trap” (Galli et al. 2001). The tidal reach has chronically low dissolved oxygen levels that

threaten aquatic life and high bacterial levels that make it unsafe for swimming and other water contact activities.

Through a series of agreements, beginning in 1984, local, state, and Federal government agencies have committed to cooperative efforts aimed at restoring the river (Metropolitan Washington Council of Governments 1999). The parties have made progress in implementing measures that should improve water quality, including improving stormwater management, reducing combined sewer overflows and trash, changing land use management to protect sensitive headwater tributaries, and increasing riparian forest buffers; the current agreement calls for continued efforts (Anacostia Watershed Restoration Committee 2001).

3.3.2.3 Rock Creek

Because Rock Creek Park surrounds the entire length of Rock Creek in D.C. and Maryland parks surround most of its length upstream from the District, Rock Creek experiences fewer adverse water quality impacts from urbanization than does the Anacostia River. However, creek water quality is affected by sedimentation and other contaminants associated with urban stormwater runoff (EPA 1997).

3.3.2.4 Patuxent River

Upland streams in the Patuxent River watershed are well oxygenated (only 1% are reported to have dissolved oxygen levels below 5 mg/L), but stream bank instability and erosion reduce biotic habitat quality and contribute contamination to downstream areas (Maryland DNR undated-a). In the tidally influenced area of the main channel, salinity increases in the downstream direction, ranging from fresh to moderately saline. Nutrient loading is a water quality concern throughout the watershed, contributing to eutrophication and oxygen depletion in the lower estuary (Maryland DNR undated-c).

3.3.2.5 Chesapeake Bay

A principal focus of concern for Chesapeake Bay water quality is ecosystem health, which is threatened by excessive loading of nutrients (Section 3.4.2). The historic *Chesapeake Bay Agreement of 1983* established the Chesapeake Bay Program with the goal of restoring the Bay (CBP undated). Through this Agreement, which has been updated and revised several times, Pennsylvania, Maryland, Virginia, the District of Columbia, EPA, and the Chesapeake Bay Commission have committed to a coordinated set of goals and targets for restoration of the Bay ecosystem, including its water quality.

Excessive loading of nitrogen, a nutrient, has been identified as one major contributor to various ecological problems in Chesapeake Bay. (See Section 3.4.2.) Nitrogen occurs naturally in soil, animal waste, plant material, and the atmosphere. In addition to these natural sources,

sewage treatment plants, industries, vehicle exhaust, acid rain, and runoff from agricultural, residential, and urban areas contribute nitrogen to the Chesapeake Bay and its rivers. One of the specific goals set by the Chesapeake Bay Program to achieve the overall objectives of the Chesapeake Bay Agreement is to reduce annual nitrogen input to the Bay to no more than 175 million lb (79 million kg) by 2010. This value is 162 million lb (74 million kg) less than the estimated 1985 input of 337 million lb (153 million kg). Between 1985 and 2004 estimated total nitrogen input to the Bay was reduced by 67 million lb/yr (30 million kg/yr) (41% of the goal), with the biggest improvement coming from reductions in point-source loadings, such as from sewage treatment plants (CBP 2005). The majority of the future reductions in nitrogen loading to the Bay are expected to come from land-based measures such as reducing farm runoff into streams.

Another important source of nitrogen in the Bay is atmospheric deposition (both on land in the watershed and directly on water). Atmospheric sources are estimated to contribute about 91 million lb (41 million kg) of nitrogen to the Bay annually. In 1985 this represented 27% of the nitrogen entering the Bay; by 2000 the estimated fractional contribution from atmospheric deposition had increased to 32% due to reductions in inputs from other sources. About three-quarters of the atmospheric nitrogen that reaches the Bay is estimated to have been emitted in the form of NO_x (Blankenship 1997). In the seven-state region (i.e., Maryland, Virginia, Pennsylvania, New York, West Virginia, New Jersey, and Ohio) estimated to produce most of the air emissions that contribute nitrogen to the Bay, utilities are estimated to be responsible for 38% of the NO_x emissions, cars and trucks 35%, industries 6%, and other sources 21% (CBP 2000).

Much of the atmospheric nitrogen that is deposited on land within the Bay watershed is utilized in biological processes and retained in the ecosystem, so that it is not delivered to the Bay (CBP STAC 1996). Thus, delivery of atmospheric nitrogen to the Bay is estimated based on landscape characteristics, data from acid-deposition monitoring, and other data. Maps of estimated per-hectare delivery of nitrogen to the Bay from all parts of the watershed (Brakebill and Preston 2004) indicate that the total delivery of atmospheric nitrogen to the Bay (in all chemical forms) is about one-tenth to one-third of the atmospheric nitrogen estimated to be deposited to the land surface as NO_x.

Plans for achieving the 2010 nitrogen goal assume that input from atmospheric deposition will be reduced by 8 million lb/yr (3.6 million kg/yr) between 1985 and 2010 as a result of the implementation of new or proposed regulations aimed at achieving Clean Air Act mandates to reduce acid rain and ozone and to limit NO_x emissions from automobiles (Blankenship 1997, 2004). The Chesapeake Bay Program has not established any location-specific targets for reducing atmospheric nitrogen input, which can originate from sources outside the watershed as well as sources within the watershed.

3.3.2.6 Acid deposition

Acid deposition (often called acid rain), due to the dry or wet deposition of oxides of nitrogen and sulfur in the air, is a concern for water quality and ecosystems in the Appalachian mountains and northeastern United States. Acids derived from air emissions have the potential to dissolve, and thus mobilize, aluminum and other metals in soils and sediments, introducing toxic metals into surface waters.

Streams and lakes most susceptible to the impacts of acid deposition are those in watersheds where soils lack carbonate minerals and other alkaline constituents that can neutralize acids deposited from the atmosphere. Such watersheds are considered to be "poorly buffered." In the state of Maryland approximately 96% of the 636 mi^2 (1,650 km^2) portion of the Potomac River watershed surrounding the District of Columbia (including Maryland portions of the Anacostia watershed) and 98% of the Patuxent River watershed are classified as "well buffered" against acid rain (Maryland DNR undated-a and undated-b). Thus, in the watersheds most likely to receive atmospheric deposition of Plant emissions, surface waters are not particularly susceptible to adverse effects from acid deposition.

3.4 Ecological Resources

The Plant is located on the western bank of the Potomac River, in the Chesapeake Bay watershed (Figures 3.3-1 and 3.3-2). The region around it is a highly urbanized ecosystem that includes the District of Columbia. Development has transformed the ecological resources of the region, and they are greatly changed from early historical conditions (EPA 1997). The ecological condition has, however, improved from the highly degraded situation that was prevalent in the late 1950s and early 1960s, and the region continues to support terrestrial, aquatic, and wetland resources.

3.4.1 Terrestrial Resources

3.4.1.1 Vegetation

Since the turn of the 20th century, approximately 75% of the forest cover in the District of Columbia has been eliminated by human activities (EPA 1997). Regionally, tree cover declined more than 30% from 1972 to 1997 (American Forests 2002). In many places intentional plantings or invasions of exotic trees and other plants have displaced and substantially altered the native vegetation (EPA 1997). Agricultural and forest land cover are, however, still predominant in some parts of the region.

Daingerfield Island, which is administered by the National Park Service as part of the George Washington Memorial Parkway, lies about a quarter mile (less than a half kilometer) north of the Plant (Figure 3.4-1). No longer geographically an island, this flat 107-acre (43-ha), mostly wooded peninsula includes a large patch of forest on the eastern portion of the island with common suburban trees and understory plants (NPS 2002).

The National Park Service administers the land between the Potomac River and the Plant. This expanse includes a bike path that runs south from Daingerfield Island past the Plant and a small wooded area near the Plant at the edge of the Potomac River. (See Figure 2-2.) The vegetation in the small wooded area is similar to that on Daingerfield Island, common suburban tree and understory plant species.

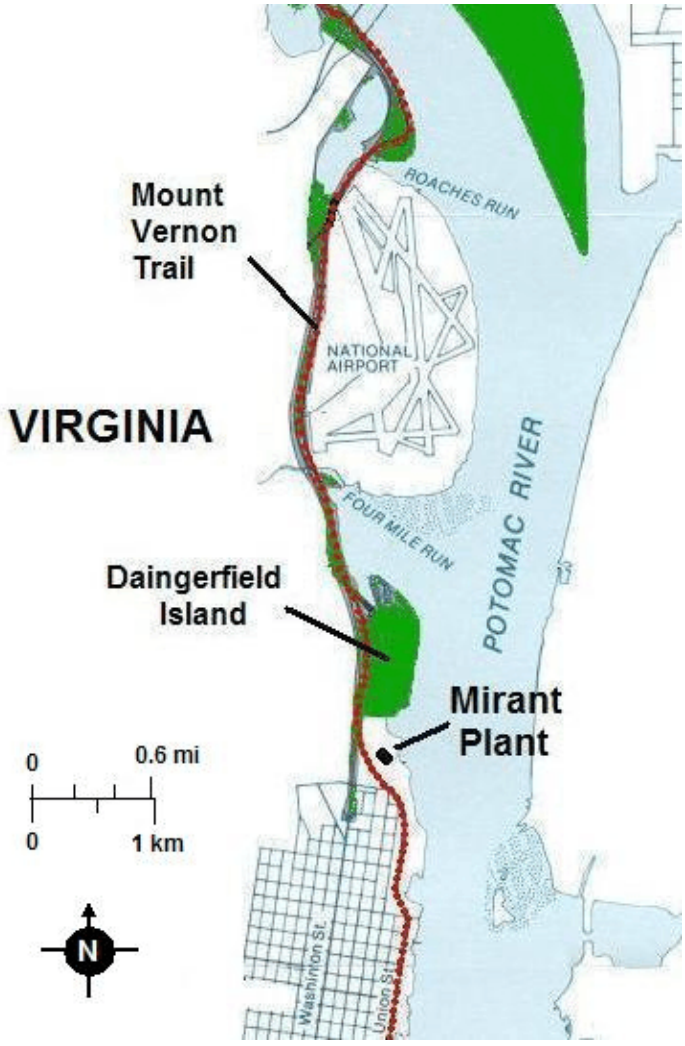


Figure 3.4-1. Location of National Park Service trail that passes the Plant.

3.4.1.2 Wildlife

Many of the animal species originally present in the D.C. region disappeared long ago (EPA 1997). Wildlife in the region is now dominated by opportunistic species characteristic of urbanized areas. Animals tolerant of human activities (e.g., opossums, raccoons, squirrels, black and Norway rats, house mice, stray cats and dogs) have increased in abundance due to the absence of larger predators and the abundant food offered by garbage. Bird species reflect a change from predominantly forest interior species to species representative of mixed land uses.

Wildlife on Daingerfield Island includes common urban species such as small mammals and birds (NPS 2002). Larger animals could possibly use the forest there for habitat. However, because the forest patch is separated from other forested areas by roadways, fields, and water bodies, the movement of large animals into the peninsular forest may be limited. The wooded

area near the Plant is also too small and too isolated by roadways, fields, and water bodies to provide habitat that could be easily used by larger animals.

3.4.1.3 The Mirant Plant site

The 28-acre (11-ha) Plant site is almost entirely covered by facilities related to coal storage and electric power generation. However, it also includes a 1,500 ft^2 (140 m^2) wildflower garden planted with woody and herbaceous vegetation for insects and pollinators.

Animals on the site include common urban wildlife species such as small mammals and birds. Artificial nesting structures for purple martins, eastern bluebirds, bats, and peregrine falcons are located within the small scattered areas of wildlife habitat.

3.4.2 Aquatic Resources

Aquatic ecosystems with the most potential to be affected by the Order include those in the Chesapeake Bay and some of its tributaries, particularly the Potomac, Anacostia, and Patuxent rivers and Rock Creek. (See Figures 3.3-2 and 3.3-3 and Section 3.3.) Coal-fired power plants can impact aquatic resources directly by the cooling water withdrawals and discharge of aqueous effluents and indirectly by the deposition of air pollutants (e.g., acid rain) into watersheds. The Plant withdraws cooling water from and discharges back to the Potomac River. The other rivers and the Chesapeake Bay are potentially affected indirectly by atmospheric deposition.

3.4.2.1 Potomac River

The estuarine portion of the Potomac River adjacent to the Plant supports aquatic communities that are recovering from past stresses. Historically the Potomac River supported dense stands of bay grasses along its entire length, but much of it was lost by the late 1930s (EPA 1997). A dense and wide patch of bay grasses has regrown and currently stretches from the Virginia Potomac shoreline at National Airport to the middle of the Potomac, extending past the southern tip and along the northern and eastern edges of Daingerfield Island that lies north of the Plant (NPS 2002). (See Figure 3.4-1.)

A large, tidally influenced river, the Potomac once possessed an exceptionally diverse and productive fish community, but species abundance and diversity are low compared to historic levels (EPA 1997). The Potomac River watershed supported large numbers of both resident, freshwater fish and anadromous fish (i.e., species that spend their adult lives in saltwater and spawn in freshwater), such as shad and river herring (*Alosa* sp.).

Even though the river has been degraded by the effects of human activities, a wide variety of fish species still occur in it. Many of these are exotic species (e.g., largemouth [*Micropterus salmoides*] and smallmouth bass [*Micropterus dolomieu*], walleye [*Sander*

vitreus]). Some native and exotic species present in the river (e.g., catfish [*Ictalurus punctatus*], crappie [*Pomoxis* sp.], sunfish [*Lepomis* sp.], largemouth and smallmouth bass, walleye) are important recreational species. The northern snakehead (*Channa argus*), a fish from Asia that has attracted public interest because it preys on other fish and can survive several days out of water, is believed to be established in the Potomac River and its tributaries (Fuller 2006). The estimated total fish abundance in the Potomac-Washington Metro Basin, which includes the Anacostia and Potomac rivers and a number of creeks, is 4.9 million fish (Maryland DNR undated-b).

An indication of the particular fish species that are affected by the Plant's cooling water withdrawals can be obtained from entrainment and impingement studies. Studies of aquatic organisms impinged (trapped) on the intake screens at the Plant during 2003-2004 provided information on the species that occur in that stretch of the Potomac (Personal communications between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, July 24, and August 18, 2006). The main fish species found were white perch (*Morone americana*), gizzard shad (*Dorosoma cepedianum*), blueback herring (*Alosa aestivalis*), and channel catfish. Striped bass (*Morone saxatilis*) and American shad (*Alosa sapidissima*), commercially important fishes, were found in low numbers. Earlier impingement studies also observed gizzard shad and white perch, many of which were juveniles, stunted, or already diseased prior to impingement (Pepco 1982).

The benthic macroinvertebrate community in the tidally influenced river near the Plant includes a mix of freshwater organisms that are tolerant of exposure to low salinity and estuarine organisms that are tolerant of fresh water (http://www.dnr.state.md.us). Benthic organisms are affected by oxygen depletion that occurs in the bottom waters during summer months. The freshwater tidal Potomac does not support shellfish of commercial value, but it does include large populations of Asiatic clams (*Corbicua fluminea*), an undesirable invasive species (EPA 1997).

3.4.2.2 Anacostia River

The Anacostia River estuary has some of the poorest water quality in the Chesapeake Bay system and is, thus, in a degraded ecological condition (EPA 1995). Many miles of stream habitats have been severely degraded by urbanization, which has profoundly altered the flow, shape, water quality, and ecology of streams in the watershed. Stressors of concern in the river are described in Section 3.3.2.2.

Urbanization has caused the loss of nearly 50 percent of the forest cover in the basin, including much of the stream-side or riparian vegetation and other wetlands. (See Section 3.4.3.)

As a large, tidally influenced freshwater river like the Potomac, the Anacostia also has the capacity to support many diadromous as well as resident fish species. Even though the river has been degraded by the effects of human activities, a wide variety of fish species still occurs in it. Numerous man-made fish barriers, however, block migration of fish.

The tidal reach of the river has chronically low dissolved oxygen levels that threaten aquatic life. (See Section 3.3.2.2.) The periodic lack of dissolved oxygen is the likely reason that substantial clam populations are absent from the river (EPA 1997). The macroinvertebrate communities in the river are severely degraded compared to those in the Potomac.

Implementation of the Anacostia Watershed Restoration Agreement (Section 3.3.2.2) has resulted in some improvement in aquatic habitat conditions (EPA 1997, Anacostia Watershed Restoration Committee 2004).

3.4.2.3 Rock Creek

As the largest stream in D.C., Rock Creek has historically supported substantial populations of recreationally important fish species and, through its direct connection to the Potomac River, large numbers of anadromous species (EPA 1995). The present anadromous fish populations and resident fish communities reflect the harmful effects of polluted runoff, barriers to fish movement, and over fishing. Nonnative fish species (e.g., largemouth bass, bluegill [*Lepomis macrochirus*], carp [*Cyprinus carpio carpio*]) now constitute a significant part of the fish community. Some species that were historically present in Rock Creek have apparently been extirpated from the watershed (e.g., white perch, trout-perch [*Percopsis omiscomaycus*]). In contrast, populations of anadromous alewife (*Alosa pseudoharengus*) and blueback herring appear to be healthy. Even though instream impediments to fish movement probably affect these species and prevent them from passing far upstream, schools of hundreds of individuals occur at several locations.

In contrast to the mainstem, fish communities in tributaries of Rock Creek are small or absent (EPA 1995). Episodic water quality problems (e.g., low flows, flooding, scouring during storm events) and polluted runoff are likely contributing factors.

Overall, the condition of the benthic macroinvertebrate communities in Rock Creek is poor. However, the creek contains several spring-dependent species of isopods, ostracods, and amphipods (EPA 1995), including one amphipod that is listed as an endangered species (Section 3.4.4.1).

3.4.2.4 Patuxent River

Stream quality for fish communities in the Patuxent River is poor in over 50% of the stream miles; only 18% are considered to be in good condition for fish (Maryland DNR undated-a). The Patuxent River watershed includes an estimated 1.1 million fish of 44 species in its wadeable streams. Four species in the basin are at risk of local extinction: American brook lamprey (*Lampetra appendix*), glassy darter (*Etheostoma vitreum*), stripeback darter (*Percina notogramma*), and warmouth (*Lepomis gulosus*). The wadeable tributary streams of the watershed serve as a nursery for the five gamefish species that are found there (i.e., largemouth

bass, smallmouth bass, chain pickerel [*Esox niger*], brown trout [*Salmo trutta trutta*], and rainbow trout [*Oncorhynchus mykiss*]), as most individuals are not of harvestable size.

3.4.2.5 Chesapeake Bay organisms

The sheltered waters of Chesapeake Bay, the largest estuary in the U.S., are exceptionally productive. The Bay is a complex ecosystem that provides homes, protection, and food for many species, including fish, shellfish, and turtles (CBP undated, Alliance for the Chesapeake Bay undated).

Bay grasses, a form of naturally submerged aquatic vegetation, are important to the Chesapeake Bay ecosystem (CBP undated). Bay grasses produce oxygen, supply food for many species (especially waterfowl), offer shelter and nursery habitat for fish and shellfish, reduce wave action and shoreline erosion, absorb excess nutrients (e.g, nitrogen, phosphorus), and trap sediments.

More than 300 species of fish, including 32 year-round species, live in the Bay and its tributaries or use its waters as they migrate along the Atlantic Coast (Alliance for the Chesapeake Bay undated). Migrating fish can, however, no longer reach many stream habitats due to the presence of dams, inadequate culverts, and other barriers to their passage (EPA 1997).

The Bay acts as a nursery for crabs, oysters, and many other species of shellfish (Alliance for the Chesapeake Bay undated). While many of these species, particularly blue crabs (*Callinectes sapidus*), are still commercially important, oyster (*Crassostrea virginica*) populations have declined to about one percent of historical levels.

3.4.2.6 Chesapeake Bay stresses

Hydrological changes, sedimentation, and pollutant loading have degraded aquatic habitats throughout Chesapeake Bay. The cooperative efforts and guidance of the Chesapeake Bay Program have led to improvements, including reduced levels of nutrients and sediments in the Bay and increased availability of dissolved oxygen for the Bay's aquatic biota, but they have not fully restored the health of the Bay (CBP undated). The biggest problems currently facing the Bay's ecosystem and making restoration difficult are excess nutrients, chemical contaminants, air pollution, and landscape changes. (See Section 3.3.2.5.)

Nutrient loading contributes to excessive algal growth, which in turn depletes dissolved oxygen and reduces water clarity. Harmful blooms of *Microcystis* and other cyanobacteria (blue-green algae) that are toxic to humans and other mammals can occur in the fresh-water and low-salinity portions of the Bay and in tributary estuaries (e.g., the Potomac River). In addition, suspended sediment loading and the presence of toxic substances in Bay sediments stress Bay biota.

3.4.3. Wetlands and Riparian Habitats

Wetlands act as water-storage basins and provide vital habitats for a rich diversity of wildlife, including threatened and endangered species (EPA 2006d). They also reduce flooding and storm damage, minimize erosion of uplands, improve water quality by filtering pollutants, and support tourism and the hunting and fishing industries.

Many of the wetlands in the region have been degraded and are of poor quality, but some continue to provide habitat for waterfowl, wildlife, fish, and shellfish (EPA 1995).

Much of the area (e.g., the District of Columbia) was initially built by filling in extensive areas of marshes and swamps along the Potomac and Anacostia rivers (EPA 1997). Such wetlands originally comprised about half the area within the boundaries of the city, totaling more than 9,600 acres (3,900 ha) in 1790. In the early 1990's only 845 acres (342 ha) of wetlands remained in the District, a decrease in area of more than 90% in 200 years.

Riparian, or stream side, vegetation is especially important to the integrity of the District of Columbia ecosystem because it buffers aquatic resources from developed areas and provides habitat for terrestrial species near water (EPA 1997). Contiguous riparian habitats also provide migration corridors for wildlife, a critical factor in urbanized environments. Because Rock Creek Park surrounds the entire length of Rock Creek in the District and Maryland parks surround most of its length beyond the District, the area along Rock Creek is the most important terrestrial and riparian resource in the city.

Within the Anacostia River watershed nearly 75 percent of the freshwater wetlands have been destroyed. Of the original 2,600 acres (1,100 ha) of emergent tidal wetlands in the watershed, less than 100 acres (40 ha) remained in the early 1990s (EPA 1995); by 2003 ongoing restoration efforts had increased the area of tidal wetlands to 123 acres (50 ha) (Anacostia Watershed Restoration Committee 2004). Parklands along the Anacostia River do not provide benefits similar to those along Rock Creek because they are not protected natural areas, but rather are reclaimed wetlands in the form of sparsely wooded lawns. They have the potential, however, to provide such benefits, especially if riparian restoration is coordinated with ongoing restoration of wetlands.

The Federal government maintains 80% of the property bordering the Potomac River, Anacostia River, and Rock Creek drainage basins in the District of Columbia, thus providing some protection to their riparian areas (EPA 1997).

3.4.4. Special Status Species

3.4.4.1 Federally listed species

The Plant’s NPDES permit names three species listed as threatened or endangered under the Federal Endangered Species Act (ESA) that could occur at locations in or near the District of Columbia, including the Potomac River drainage. These are the endangered Hay's Spring

amphipod (*Stygobromus hayi*) and shortnose sturgeon (*Acipenser brevirostrum*) and the threatened bald eagle (*Haliaeetus leucocephalus*).

The Hay's Spring amphipod is restricted to a small area in Rock Creek in D.C., a very specialized habitat, and the species is not found elsewhere (Personal communication between A. Moser, U.S. Fish and Wildlife Service, and M.S. Salk, Oak Ridge National Laboratory, June 19, 2006).

The shortnose sturgeon exists as 19 distinct populations that occupy and spawn in rivers and bays from Canada to Florida (Keeney 2002). The Potomac River is one of several tributaries in the Chesapeake Bay drainage that appear to have suitable habitat for it. The Shortnose Sturgeon Recovery Plan (NMFS 1998) reports that one shortnose sturgeon was captured in 1996 at the mouth of a small creek off the Potomac River about 50 miles (80 km) downstream from the Plant. Between 1996 and 2002 six sturgeon were captured many miles downstream from the Plant in the lower and middle tidal Potomac River (Keeney 2002). Two mature, egg-bearing females were captured in the river in September 2005 and March 2006, suggesting that a spawning population continues to exist in the river system (Appendix D). The female caught in September 2005 overwintered in a creek approximately 24 miles (39 km) downstream of the Plant. Population dynamics in the Potomac River have not been documented, but it is likely that they migrate past the Plant in the spring (March - June) while moving to and from the presumed spawning grounds near Little Falls, Maryland (about 11 miles [18 km] upstream from the Plant). It is unknown if the sturgeon occur in this region of the river during other times of the year. However, if appropriate forage items are present, they could live in the area in the summer and fall. The shortnose sturgeon has not been reported among the species impinged by the Plant (Personal communication between D. Knight, Mirant, and M.S. Salk, Oak Ridge National Laboratory, July 24, 2006).

While a pair of bald eagles lived for several years about two miles (3 km) south of the Plant near the Woodrow Wilson Bridge (WWBP 2006a) until the recent death of the female (WWBP 2006b), bald eagles are only rarely seen near the Plant (Personal communication between D. Knight, Mirant, and M.S. Salk, Oak Ridge National Laboratory, July 24, 2006). (See Figure 3.3-3.)

The Virginia Natural Heritage Resources information database indicates that no Federally listed threatened or endangered species occur in the city of Alexandria, but it names two Federal species of concern[5] that could occur there: the Northern Virginia well amphipod (*Stygobromus phreaticus*) and Torrey's mountain-mint (*Pycnanthemum torrei*) (VNHR 2006). The amphipod is found only in caves (NatureServe 2006). In Virginia Torrey's mountain-mint occurs in dry, rocky, upland, deciduous woods; along roadsides; and in thickets near streams (NatureServe 2006). There is no suitable habitat for either species on the Plant site.

[5] "Species of concern" means a species that might be in need of conservation action (FWS 2006). Such species receive no legal protection, and use of the term does not necessarily imply that a species will eventually be proposed for listing.

3.4.4.2 State-listed species

The Virginia Natural Heritage Resources information database indicates that the only state protected species that occurs in the city of Alexandria is the threatened wood turtle (*Glyptemys insculpta*) (VNHR 2006). Wood turtles live along permanent streams during much of each year, but in summer they may roam widely overland and can be found in a variety of terrestrial habitats adjacent to streams, often associated with the margins of woods (NatureServe 2006). There is no suitable habitat for the species on the Plant site.

3.5 Waste Management

Except for small quantities of fly ash that are used beneficially (Section 2.4.3), fly ash from the Plant is disposed of in the Brandywine Fly Ash Facility, a landfill owned and operated by Mirant Ash Management LLC and used solely for disposal of coal combustion ash. The landfill, located in southeastern Prince George's County, Maryland (east of the community of Brandywine) (Figure 2.4.1), is also used for disposal of fly ash from Mirant's Chalk Point Generating Plant on the Patuxent River estuary in southeastern Prince George's County.

The 178-acre (72-ha) site currently used for waste disposal is part of a larger area that was formerly surface-mined for gravel and that has been used for coal combustion ash disposal since 1971. Surrounding land uses include an active sand and gravel mining operation, agricultural fields, forest, a high-voltage electric transmission line, and other landfills. The landfill site has a low-permeability base of compacted native soil (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006) and is equipped with a leachate collection system. Ash is delivered to the landfill by dual-axle dump trucks and is placed and compacted in the landfill in 2-ft (0.6-m) layers. On weekdays during peak power-generation periods the landfill receives approximately 60 truckloads of ash from the two generating stations; average daily ash receipts are approximately 70% of peak daily receipts.

Stormwater runoff and leachate from the landfill drain to collection ponds where a sprinkler pump provides aeration, water quality is monitored, pH is adjusted, and solids settle out before the water is discharged to the upper reaches of Mataponi Creek (a tributary to the fresh water tidal river reach of the Patuxent River) and an unnamed tributary to the creek (Baxter 2006). Dust is controlled by periodically watering haul roads and the active disposal area, using water recycled from the collection ponds (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Landfill site plans limit the final height of the fill to a elevation of 260 ft (79 m) above mean sea level (MSL), or about 70 ft (21 m) above the original land surface grade (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). Areas of the landfill that have reached their maximum

design height are capped with a 3-ft (1-meter) thickness of soil and seeded to establish a vegetative cover. In January 2005 the landfill was calculated to have a remaining capacity of 2.07 million yd^3 (1.58 million m^3), providing sufficient capacity for disposal of the two power plants' projected ash generation for about 7 years, or approximately through the middle of 2012 (GB&B Inc. 2005).

Disposal facilities for coal combustion ash are not subject to state solid waste regulation in Maryland (Personal communication between R. Daniel, Maryland Department of Environment Customer Service Center, and E.D. Smith, Oak Ridge National Laboratory, June 6, 2006), but local zoning requirements and state wastewater regulations apply. The Brandywine facility operates under a series of special exceptions from Prince George's County zoning restrictions. The most recent special exception for 12 years of continued operation was approved by Maryland-National Capital Park & Planning Commission, Prince George's County Planning Department in 1991 (Baxter 2006). In 2005 Mirant filed an application for a 15-year extension to this special exception (Baxter 2006); the application is currently pending.

Discharge of wastewater from the site, including storm water runoff, collected leachate, and truck wash water, is permitted under MDE Discharge Permit 02-DP-1389 (NPDES Permit MD0054836), issued by the Maryland Department of the Environment. The current 5-year discharge permit is effective September 1, 2005, to August 31, 2010. The permit limits discharge to a pH range of 6 to 9 pH units, total suspended solids of no more than 35 mg/L as a monthly average and 70 mg/L as a daily maximum, and total iron of no more than 3.5 mg/L as a monthly average and 7.0 mg/L as a daily maximum. Discharge monitoring requirements under the permit include monthly flow and monthly measurements for pH, total suspended solids, hardness, iron, copper, lead, selenium, and zinc. Six groundwater monitoring wells in the vicinity of the landfill are monitored quarterly for pH; total dissolved solids; chloride; sulfate; and dissolved aluminum, cadmium, manganese, copper, iron, lead, silver, and nickel. No surface or groundwater problems are currently identified at the site (Baxter 2006). There have been no regulatory violations since 1996 when a discharge from one of the wastewater ponds exceeded the permit limit for total suspended solids (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

3.6 Transportation Resources

The primary transportation activities associated with Plant operations are (1) trains traveling to and from the Plant to deliver coal and trona and (2) trucks traveling to and from the plant to remove ash. The following sections discuss the affected local environment for these rail and road operations.

3.6.1 Rail

Trains enter and exit the Plant to deliver coal and trona via a short rail spur from the CSX, Inc., main rail line located west of North Henry Street (Figure 3.6-1). The City of Alexandria allows the Plant to conduct rail operations during two daytime periods (11 a.m. to 12 p.m. and 1 p.m. to 3 p.m.) and one nighttime period (7 p.m. to 11 p.m.) from Monday through Saturday. (The Plant does not receive rail deliveries on Sundays.) Daytime rail operations involve removing empty rail cars from the Plant during each of the two daytime periods to avoid blocking vehicular traffic on the George Washington Parkway (Figure 3.6-1). Nighttime rail operations involve deliveries of coal and trona (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

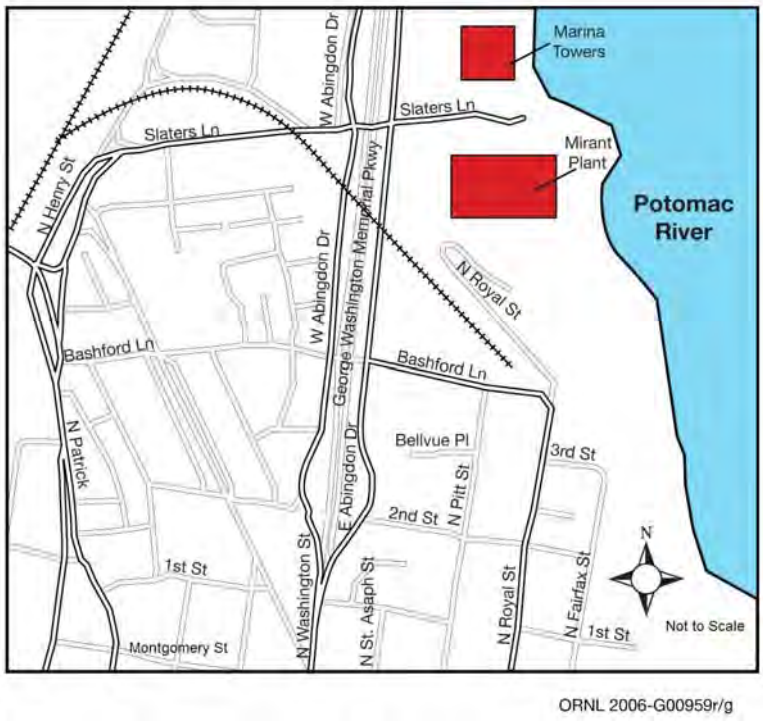


Figure 3.6-1. Access routes near the Mirant Plant.

3.6.2 Road

Trucks enter and exit the Plant to remove ash via a gated entrance located on North Royal Street (Figure 3.6-1). The trucks haul ash from the Plant to the Brandywine Fly Ash Facility in Prince George's County, Maryland (Figure 2.4-1).

From the Plant the trucks travel south on North Royal Street, then west on Montgomery Street (Figure 3.6-1). Neither the Virginia Department of Transportation nor the City of Alexandria maintains data on annual average daily traffic[6] or level-of-service (LOS)[7] for North Royal Street, but it is a local street with relatively little traffic and an existing level-of-service (LOS) at or near "A" (Personal communication between B. Garbacz, Transportation Engineer,

[6] The annual average daily traffic is "an estimate of typical daily traffic on a road segment for all days of the week, Sunday through Saturday, over the period of one year" (VDOT 2004).

[7] Level-of-service (LOS) is "a standard measurement used by transportation officials which reflects the relative ease of traffic flow on a scale of A to F, with free-flow being rated LOS-A and congested conditions rated as LOS-F" (FHWA 2006).

City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). On Montgomery Street annual average daily traffic is 3,800 vehicles (VDOT 2004).

Once the trucks reach the intersection of Montgomery Street and Henry Street (State Route 1) (Figure 3.6-1), they travel south on Henry Street to access Interstate 495 (I-495 or the Capital Beltway) (Figure 2.4-1). The trucks then travel east on I-495 North, crossing the Potomac River on the Woodrow Wilson Memorial Bridge, which serves as a major connector between Virginia and Maryland (Figure 3.3-3). On entering Maryland, trucks exit onto Maryland Route 5 and travel south. The trucks continue to travel south on Maryland Route 381 (Brandywine Road) to North Keys Road, on which the Brandywine facility is located. Table 3.6-1 lists the existing traffic volumes on each of these roads between Henry Street in Alexandria and the Brandywine facility in Maryland.

Table 3.6-1. Roads traveled by the ash removal trucks between Henry Street and the Brandywine Fly Ash Facility

Road	Segment	Annual Average Daily Traffic
Henry Street (Route 1)	Southbound to I-495 North (Capital Beltway)	22,000 to 25,000
I-495 North	Eastbound into Maryland via the Woodrow Wilson Memorial Bridge	154,000
I-495 North	Eastbound in Maryland to Maryland Route 5	142,925 to 174,800
Maryland Route 5	Southbound to Maryland Route 381	62,450 to 112,050
Maryland Route 381 (Brandywine Road)	Southbound to North Keys Road	4,850 to 12,150
North Keys Road	Southbound to the Brandywine Fly Ash Facility	No data available

Sources: VDOT 2004; MDOT 2005

The road network used to transport ash to the landfill is affected by ongoing construction activities associated with the Woodrow Wilson Bridge Project (WWBP 2006a). This project, which is scheduled for completion in December 2012, involves a series of roadway and interchange improvements along a 7.5-mile-long (12-km-long) segment of I-495 that extends from the Telegraph Road interchange in Virginia to the Route 210 interchange in Maryland. The project's centerpiece, widening and improving the Woodrow Wilson Memorial Bridge, is scheduled for completion in December 2008.

Access to the Brandywine Fly Ash Facility from North Keys Road is via a private road that is shared by an adjoining sand and gravel mining and wet processing facility. During peak winter and summer months total hauling operations at the Brandywine Fly Ash Facility consist of approximately 60 truckloads per day. This total includes trucks from the Plant and from Mirant’s Chalk Point Power Plant in Prince George’s County, Maryland. Typical weekday

haulage activity at the Brandywine facility is approximately 70 percent of the seasonal peaks (Baxter 2006).

There are some existing traffic problems on Maryland Route 381, which is used to access the Brandywine facility. Although the State of Maryland's accident records indicate that this road operates without any significant safety deficiencies, certain intersections along Maryland Route 381 function inadequately and have a low LOS based on existing traffic volumes (Baxter 2006).

In April 2005 Mirant filed with the Maryland-National Capital Park and Planning Commission an Application for Special Exception for a Sanitary Landfill (Fly Ash) (Baxter 2006). That application includes information about transporting ash to the Brandywine facility. Mirant's Application was reviewed by the Maryland Department of Transportation State Highway Administration and the Prince George's County Department of Public Works and Transportation. The Department of Public Works and Transportation conducted a traffic study for Mirant's Application in which it assumed that there would be "an increase in through traffic percent along key roadways in the study area." The traffic study examined impacts for seven intersections under three scenarios:

- existing traffic conditions,
- the addition of 13 background developments whose impact would affect some or all of the study intersections, and
- traffic volumes representing total background conditions combined with projected facility site trip generation (the 20-year build-out projection).

Analysis of this third scenario (which includes Mirant's Application, as well as 13 other "background" developments over a 20-year period) indicated impacts on the seven intersections as listed in Table 3.6-2. Ash hauling associated with pre-shutdown operations at the Plant was a minor contributor to these existing traffic problems.

The Department of Public Works and Transportation traffic study notes that the State Highway Administration has required Mirant to address the failing levels of service at these intersections along Maryland Route 381. In particular, the study notes that the intersection of Maryland Route 381 and U.S. Highway 301 "operates inadequately based on existing traffic volumes (LOS-E in the morning) and will worsen significantly with the inclusion of approved background developments." The study adds that pursuant to State Highway Administration's comments, Mirant "has offered no improvements that would ameliorate the inadequacies at that intersection" (Baxter 2006).

Table 3.6-2. Traffic impacts projected in Mirant's *Application for Special Exception* for the road intersections used to access the Brandywine Fly Ash Facility

Intersection	Level-of-Service during after-midnight and morning hours	Level-of-Service during afternoon and evening hours
North Keys Road/Gibbons Church Road (unsignalized)	B	A
Maryland 381/North Keys Road (unsignalized)	***F***	C
Maryland 381/U.S. 301 (signalized)	***F***	***F***
Maryland 381/Baden Westwood Road (unsignalized)	***F***	B
Maryland 381/Croom Road (unsignalized)	***F***	***F***
Link—Maryland 381 (U.S. 301–North Keys Road)	E	D
Link—Maryland 381 (Croom Road–North Keys Road)	C	C

Figures in ***boldface italics*** represent failing levels of service.
Source: Baxter 2006

3.7 Minority and Low-Income Populations

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, directs each Federal agency to identify and address the "disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations." The Council on Environmental Quality (CEQ) guidance on environmental justice (CEQ 1997) states that a "minority population" should be identified where either: "(a) the minority population of the affected area exceeds 50 percent or (b) the minority population percentage in the affected area is meaningfully greater than the minority population percentage in the general population or appropriate unit of geographical analysis." The CEQ guidance defines "low-income" using statistical poverty thresholds from the Bureau of Census Current Population Reports, Series P-60 on Income and Poverty.

For this analysis DOE examined the 2000 U.S. Census data to identify any minority or low-income populations in census tract[8] (CT) 2018.01, in which the Plant is located (Figure 3.7-1), and the four block groups[9] within CT 2018.01. DOE focused on CT 2018.01 because its boundaries encompass the geographical distribution of the greatest air quality impacts from the

[8] The U.S. Census Bureau defines census tracts as small, relatively permanent statistical subdivisions of a county. Census tracts average about 4,000 inhabitants and are designed to be relatively homogeneous units with respect to population characteristics, economic status, and living conditions. Census Tract 2018.01 has a total population of 4,727.

[9] The U.S. Census Bureau defines block groups as subdivisions of a census tract. Block groups are the smallest geographic unit for which the Census Bureau tabulates sample data.

Plant. To identify minority and low-income populations within CT 2018.01 and its block groups, DOE defined a "meaningfully greater" population as one that had a minority or low-income percentage at least 10 percentage points higher than the percentages for the city of Alexandria, the state of Virginia, or the United States (whichever is lower).[10] Thus, based on the data in Table 3.7-1, DOE identified minority populations as those that have a minority percentage of at least 39.8% (10 percentage points higher than the state of Virginia) and low-income populations as those that have a low-income percentage of at least 18.9% (10 percentage points higher than the city of Alexandria).

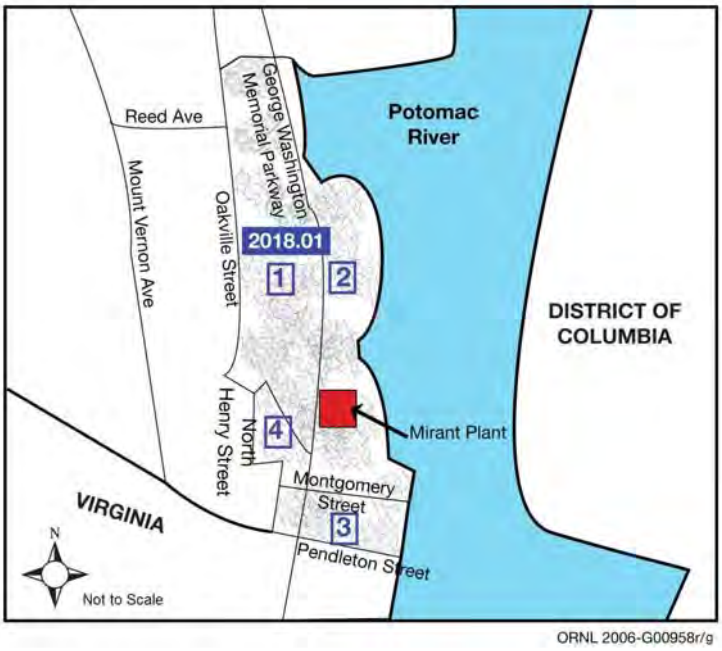


Figure 3.7-1. Block Groups 1-4 within Census Tract 2018.01.

As indicated in Table 3.7-1, the percentages of the total population in CT 2018.01 (population 4,727) that are classified as minority (27.2%) and low-income (11.1%) do not exceed DOE's threshold for identifying either minority or low-income populations. However, block group 3, which is located south of the Plant (Figure 3.7-1) and has a total population of 1,368, exceeds DOE's low-income threshold. Similarly, block group 4, which is located southwest of the Plant (Figure 3.7-1) and has a total population of 620, exceeds DOE's minority threshold. Therefore, block groups 3 and 4 of CT 2018.01 contain minority and low-income populations that meet the DOE thresholds, while block groups 1 and 2 (populations of 1,650 and 1,085, respectively) do not.

[10] The "10 percentage point" criterion is used here because it is large enough to indicate the presence of a minority or low-income population when compared to a large geographic area (i.e., the state or the nation), yet small enough to indicate minor differences in percentages among several census tracts or block groups in a small geographic area. Note that the use of a more conservative criterion, such as 5 percentage points, would not change which block groups are identified as minority or low-income populations.

Table 3.7-1. Minority and low-income data for census tract 2018.01 and its block groups (See Figure 3.7-1)

Location	Percent minority [a]	Percent low-income [b]
United States	30.9	12.4
State of Virginia	29.8	9.6
City of Alexandria	46.3 [‡]	8.9
Census tract 2018.01	27.2	11.1
Block group 1	18.9	5.0
Block group 2	6.3	9.5
Block group 3	37.8	23.3 [‡]
Block group 4	60.0 [‡]	3.4

[a] Includes all persons who identified themselves as not "white alone," plus those who identified themselves as both "white alone" and "Hispanic or Latino."
[b] Represents individuals below the poverty level as defined by the U.S. Census Bureau.
[‡] Minority or low-income population based on the DOE thresholds for percent minority or low-income.
Source: U.S. Census Bureau 2006.

4. PLANT OPERATIONS, ASSUMPTIONS, AND ENVIRONMENTAL CONSEQUENCES

This chapter begins by describing general Plant operations as authorized by the DOE Order. Next, this chapter describes the information and assumptions that DOE used to assess the impacts of the Plant under the DOE Order and a potential extension of the Order until the new 230-kV transmission lines are in service. Finally, this chapter assesses the impacts to air, human health, water, ecological resources, waste management, transportation resources, and minority and low-income populations as a result of the Order and a potential extension of the Order until the new 230-kV transmission lines are in service.

4.1 General Plant Operations as Authorized by the DOE Order

The DOE Order consists of 285 days, from December 20, 2005, to October 1, 2006. Just before the Secretary issued the Order, Mirant operated Unit 1 on an 8-8-8 basis (that is, in any given 24-hour period, it ran for eight hours at up to its maximum level of 88 MW, ran for up to eight hours at its minimum level of 35 MW, and did not run for at least eight hours), and began using trona and low sulfur Colombian coal, alone or in combination.

4.1.1 Operations as Authorized by the DOE Order until the Administrative Compliance Order (ACO)

At the time the Order was issued, Mirant had one operational trona injection unit that serviced only the Unit 1 boiler. A second trona unit became operational on January 22, 2006, and a third on March 20, 2006. Except during transmission line outages (Table 1.3-1), Mirant operated only boilers that had trona units. By April 28, 2006, Mirant had operational trona injection units installed on all five boiler units.

On January 4, 2006, DOE authorized Mirant to operate each of the two load-following or cycling units at the Plant (i.e., Units 1 and 2) up to 16 hours per day. Each unit was authorized to operate 8 hours at minimum load and up to an additional 8 hours at maximum load. In addition, DOE authorized Mirant to operate any one of the three baseload units continuously without constraint as to load or operating hours. According to Mirant's proposed operating plan, each baseload unit would operate for approximately two weeks before another baseload unit began a two-week operating period.

In January 2006, due to transmission line outages for maintenance, Mirant operated the Plant to meet the entire Central Washington, D.C., load for 21 days. No line outages have occurred since those in January. Between January and May, DOE continued to weigh other options that were available to Mirant to comply with the Order and consulted with EPA on options to increase electricity reliability while ensuring environmental protection.

4.1.2 Operation under the ACO

EPA issued its ACO to Mirant on June 1, 2006. On June 2, 2006, DOE directed Mirant to operate under the ACO during non-line outage situations, for the purpose of providing electricity reliability, and to continue operation in accordance with the DOE Order in line-outage situations.

4.1.2.1 Operations during non-line outage situations

Daily predictive modeling. Upon installation of three SO_2 monitors[11] the ACO directs Mirant, in non-line outage situations, to operate under daily predictive modeling. Under daily predictive modeling the Plant operators acquire the National Weather Service forecast for the next day for Ronald Reagan Washington National Airport and use that forecast along with their planned operating parameters as inputs to a computer modeling run for the following day using AERMOD Default[12]. If the modeling results indicate that operating the Plant under those conditions would not cause a modeled exceedance of the 3- and 24-hour average SO_2 and PM_{10} NAAQS limits, operators may run the Plant on that day using those parameters. If the results indicate that operation of the Plant would cause a modeled exceedance for these pollutants, the operators must adjust the planned operating parameters and rerun the model using the same weather forecast. The operators must continue to adjust their planned operating parameters and rerun the model until the results indicate no modeled exceedance of these pollutants. The operators then will operate the Plant the next day using those parameters. Thus, under this scenario the Plant can operate each day up to the maximum level allowed by the weather forecast for that day. The ACO only requires daily predictive modeling for PM_{10} when Mirant operates four or five units. Mirant is required to assume a PM_{10} emission rate of 0.055 lb/MBtu and to adjust operations to prevent a modeled exceedance for PM_{10}.

Other requirements of the ACO. In addition to daily predictive modeling, the ACO requires Mirant to install an audible alarm in the Plant's control room that will sound when the ambient concentration of SO_2 at any monitor reaches specified levels. When an alarm sounds, Mirant must make operational changes (e.g., increase use of trona, decrease operating level) and observe the effect of those changes on the level of SO_2 measured at the monitors. The ACO uses this alarm system to monitor the Plant's compliance with the annual SO_2 NAAQS limit. The

[11] Until June 20, 2006, when three newly installed SO_2 monitors were functioning, Mirant operated under the constraints detailed in Table 1 in the ACO. (See Appendix B.) These constraints included, for example, restrictions on number of hours of operation and SO_2 emission rate during each calendar day. For example, on days when Units 1 and 3 were operating, each unit was required to achieve a 24-hour average SO_2 emission rate no higher than 0.24 lb/MBtu and a 3-hour rolling rate no higher than 0.51 lb/MBtu, and Unit 1 was required to operate for no more than 8 hours per day above minimum power and spend at least 8 hours per day off.

[12] AERMOD Default means Version 04300 of the AERMOD computer model, currently approved for general use by EPA in accordance with 40 CFR Part 51, Appendix W, to predict NAAQS compliance. See the AERMOD text box in Section 4.3.1.

ACO also directs Mirant to undertake a "Model Evaluation Study" (MES) (text box) "to determine the best performing model for predicting the computer-modeled ambient air quality impacts" from Plant operations. To provide data for the MES and to support the alarms, Mirant installed six SO_2 monitors in locations identified in the ACO. (See Appendix B.) Lastly, the ACO puts a NO_x limitation on the Plant; at all times Mirant may not emit more than 3,700 tons (3,400 metric tons) of NO_x per year.

4.1.2.2 Operations during line outage situations

The ACO directs Mirant, in line-outage situations, to follow the DOE Order, but requires Mirant to "take all reasonable steps to limit the emissions of PM_{10}, NO_x and SO_2 from each boiler, including operating only the number of units required to meet PJM's directive and optimizing its use of trona injection to minimize SO_2 emissions." Further, the ACO requires that Mirant achieve "80% reduction of SO_2 emissions unless: 1) Mirant demonstrates ... that 80% reduction is not necessary to achieve compliance with the NAAQS; or 2) Mirant demonstrates that 80% reduction is not logistically feasible because of such factors as the quantity of available trona and the predicted duration of the outage." If Mirant demonstrates that 80% removal is not logistically feasible, it is required to submit a plan to EPA for optimizing its use of trona. However, as described in Section 4.3.1.1 and Section 5.3.1, DOE assumed 50% removal of SO_2 emissions in assessing impacts under the DOE Order and a potential extension of the Order.

Model Evaluation Study

The objective of the MES is to determine the best performing model for predicting the computer-modeled ambient air quality impacts from Plant operations. The MES proceeds by comparing the air quality impacts predicted by the AERMOD Default and those predicted by AERMOD EBD computer models to actual measured SO_2 concentrations in order to determine the better performing model. AERMOD Default is Version 04300 of AERMOD computer model, currently approved for general use by EPA. AERMOD EBD means the standard AERMOD computer model with modified direction-specific equivalent building dimensions derived from a wind tunnel study. Mirant submitted an MES protocol to EPA in July 2006 and submitted the results of the wind tunnel study to EPA in August 2006. If EPA and the VDEQ approve AERMOD EBD, Mirant must use it in its predictive modeling for the remainder of the MES period.

Mirant is to compare the actual data from the six monitors to the results of the two computer models. At the end of the study EPA and the VDEQ expect to determine which model is *best performing*. The best performing model will then be used to develop permanent emission limits for the Plant.

4.2 Assumptions and Data Used in SEA to Model Plant Operations

To the extent possible, DOE's assessment of the environmental impacts of Plant operations under the Order is based on actual operating data. However, the Plant has had several different modes of operation under the Order, and data are not available for all parameters.

Therefore, it was necessary to make some assumptions in order to assess the impacts of the Order and of the potential extension of the Order. This section describes operations under the Order and the assumptions that DOE used to estimate the environmental consequences.

4.2.1 Pre-Shutdown Operations

Before it shut down on August 25, 2005, the Plant operated its five units without SO_2 emissions controls. The Plant generated electricity at an annual average rate of 210 MW and burned about 837,000 tons (755,000 metric tons) of coal per year. Generation varied seasonally, with the highest generation occurring in the summer months when demand for air conditioning is high (Figure 4.2-1).

DOE used hourly, unit-by-unit electricity generation data, provided by Mirant, to model operations of the Plant. DOE used SO_2 emission factors it developed by analyzing detailed operation and emission data for the period December 20, 2005, through March 31, 2006. DOE assumed that the Plant emitted SO_2 at a rate of 1.05 lb/MBtu and that it emitted NO_2 at a rate of 0.35 lb/MBtu for Units 1 and 2 and 0.26 lb/MBtu for Units 3, 4, and 5.

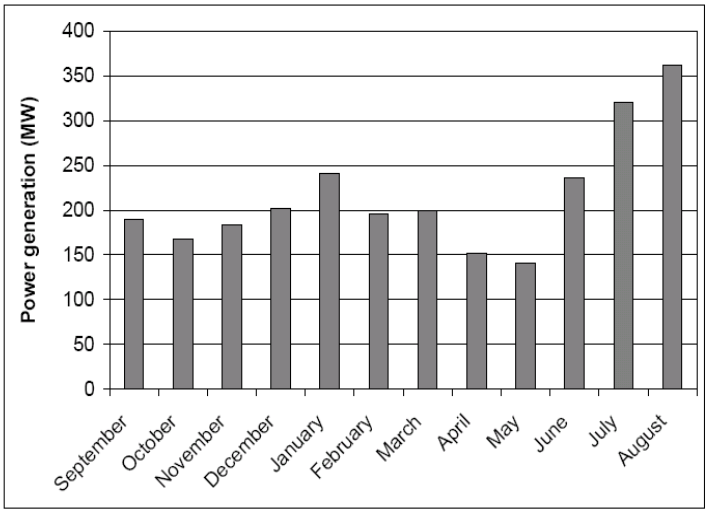


Figure 4.2-1. Monthly average power generation for September 2004 through August 2005.

4.2.2 Pre-Order Operations

Before the Secretary of Energy issued the Order, Mirant was operating Unit 1 in an 8-8-8 mode (in any given 24-hour period, the unit ran for up to eight hours at power levels up to its maximum level of 88 MW, ran for eight hours at its minimum level of 35 MW, and did not run for eight hours) and had begun using trona injection and low-sulfur coal in varying quantities. If the Order had not been issued, it is likely that Mirant would have continued to restart additional units at the Plant with the further installation of trona injection units. However, because it is impossible to know exactly what would have happened if the Order had not been issued, DOE is providing this "pre-Order" mode of operations as a basis for comparing impacts under the Order.[13]

[13] Because Mirant did not provide DOE with operations data for periods before December 20, 2005, and (continued...)

During the pre-Order mode, the Plant's Unit 1 operated for 16 hours per day with intermittent use of Colombian coal and/or trona injection. A typical day started at about 4 am with the unit being brought up to operating temperature by burning oil for about two hours. At about 6 am the unit was switched to coal and began generating electricity. The unit would reach a level close to its 88 MW capacity in about five hours, around 11 am. The unit would continue at that high power level through the afternoon and evening before making the transition to shut down status by about 10 pm. This is the 8-8-8 mode of operation.

During the pre-Order period Unit 1 consumed about 540 tons (490 metric tons) each day of coal with an average heat content of 12,000 Btu/lb and a heat rate of 12.9 million Btu per MWh (MBtu/MWh). On average, the unit emitted about 10,300 lb (4,700 kg) of SO_2 and about 4,300 lb (1,900 kg) of NO_x per day. SO_2 emission rates varied within the period due to trona injection and burning of coal with different sulfur contents. At this rate of coal consumption, one train containing 40 rail cars with 100 tons (91 metric tons) of coal per rail car could provide a week's worth of coal to the Plant. On a day when the Plant consumed 540 tons (490 metric tons) of coal that was on average 67% by weight carbon, it released about 1,300 tons (1,200 metric tons) of CO_2.

According to discharge monitoring reports that Mirant prepared for submission to EPA (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006), during December 2005 discharges to the Potomac River of cooling water and treated in-plant effluents averaged 94 million gal (356,000 m^3) per day. The reported maximum thermal discharge to the river was 969 MBtu per hour.

4.2.3 Operations under the Order and Potential Extension

Mirant provided DOE with hourly records of power plant operations for the period December 20, 2005, through March 31, 2006. These records include power production, stack gas parameters (e.g., flow rate, temperature, percent CO_2, opacity), pounds of NO_2 released per million Btu, pounds per hour of NO_2 released, pounds of SO_2 released per million Btu, and pounds per hour of SO_2 released. Table 4.2-1 is a summary of plant operations through March 31, 2006.

Mirant also supplied data on wastewater discharges for all months through June 2006 and data on total coal consumption and fly ash generation during the 3-month period March through May 2006.

The operating records described above allowed DOE to estimate plant operational parameters for each unit. DOE used those parameters to model plant operations during the Order and during a potential extension of the Order.

---

[13] (...continued)
because Mirant continued its pre-Order (8-8-8 mode) operations through December 23, DOE used December 20 through 23 to represent pre-Order operations.

Table 4.2-1. Plant operation from December 21, 2005, through March 31, 2006

Dates	Operating mode
December 20- 23, 2005	Unit 1 operated with Colombian coal and trona testing
December 24, 2005	No data available
December 25 - 31, 2005	Unit 1 operated without using low sulfur coal or trona
January 1, 2006	No data available
January 2 - 6	Unit 1 operated without using low sulfur coal or trona
January 7 - 19	All five units operated as directed by PJM for a transmission line outage; only Unit 4 had trona injection
January 20	Only Unit 4 operated
January 21 - 28	All five units operated as directed by PJM for a transmission line outage; trona injection on Units 3 and 4
January 29 - February 15	Units 1 and 4 operated with trona injection
February 16 - 17	Only Unit 4 operated
February 18 - 21	Unit 3 and Unit 4 operated
February 22 - 25	Unit 1 and Unit 3 operated
February 26 - 27	Only Unit 3 operated
February 28 - March 8	Unit 2 and Unit 3 operated
March 9	Only Unit 4 operated
March 10 - 21	Unit 4 and Unit 5 operated
March 22	Only Unit 4 operated
March 23 - 31	Unit 3 and Unit 4 operated

Note: After January 28, only units employing trona injection were operated. Because Mirant found the Colombian coal unsuitable for use at the Plant, after the initial supply was consumed, Mirant used only trona injection to control SO_2 emissions.

For the purpose of evaluating impacts for which actual emissions data are not available, DOE assumed that impacts could be scaled to power production and coal use based on pre-August 2005 data (Section 4.2.1). During the year before shutting down in August 2005, the Plant generated power at an average rate of approximately 210 MW and consumed about 832,000 tons (755,000 metric tons) of coal.

Assumptions for operations from December 20, 2005, through June 30, 2006. For the period through March 31, DOE used hourly emissions data provided by Mirant to model air emissions. For the two days for which data were not provided, DOE assumed operations were identical to the preceding day. For this period DOE used historical weather data for the specific days of operation acquired from the National Weather Service.

Beginning with April, DOE made assumptions on operating modes based on information provided by Mirant. In operating plan supplements that Mirant supplied to DOE on January 13, 17, and 24 and February 6 and 16, 2006, Mirant described combinations of SO_2 emission rates and limits on hours of operation for all combinations of two units that its modeling determined would not cause any NAAQS exceedance. To model the air quality impacts of operations during the period April 1 through May 31, 2006, DOE assumed that Mirant operated the Plant to the maximum level described in those supplements.

Assumptions for operations from July 1 through September 30. On June 2, 2006, DOE directed Mirant to operate the Plant in compliance with the ACO. The ACO directed Mirant to operate the Plant within a set of constraints on operation hours and SO_2 emission rates enumerated in the ACO until Mirant met the requirements to operate in accordance with daily predictive modeling. For the purposes of this SEA DOE assumed that the Plant operated June 1 through June 30, 2006, in a manner that produced the maximum electrical power while being in compliance with the table of operational limits in the ACO.[14]

DOE assumed that after June 30 Mirant operated at the maximum level of power generation allowed under daily predictive modeling, as described in Section 4.1.2.1, and that, except during line-outage periods, this mode of operation continued through the duration of the Order and during a potential extension of the Order through 2007. The Plant generates electric power in response to demand, at levels requested by PJM. In order to estimate how much power might be generated during non-line outage situations when operating under daily predictive modeling, DOE used the record of the last year of historical operation (i.e., the year prior to August 24, 2005; Figure 4.2-1) to produce a scenario that represents levels of operations that might reasonably be expected if it were not for environmental constraints.

Assumptions for a potential extension of the Order.[15] DOE assumed that during non-line outage periods, the Plant would produce as much power as during the year before shutting down in August 2005, while complying with the ACO. Pepco has plans for several transmission line outages that would occur during a potential extension of DOE's Order before the two new 230-kV transmission lines are put into service. Outages are planned from November 27 through December 11, 2006; and February 19 through March 5, May 2 through 15, and May 21 through June 15, 2007. During outage periods DOE assumed that the Plant generated an amount

[14] Table 1 of the ACO specifies maximum operations levels and SO_2 emission rates for individual units and for combinations of two or three units. For operations under the ACO before daily predictive modeling commenced, DOE assumed that the Plant operated two units at all times.

[15] On September 28, 2006 Secretary Bodman issued a temporary extension of the Order until 12:01 a.m., December 1, 2006 to allow time to complete the SEA and consider public comments.

of power equal to the Central D.C. load during the corresponding dates in the year ending on August 31, 2005.[16]

Mirant is planning to take units out of service beginning in the fall of 2007 to reconfigure the exhaust stacks. DOE has not modeled these planned unit outages because they are not confirmed.

4.3 Environmental Consequences

Assessment of the environmental consequences of the Order is organized by environmental resource. Consideration of cumulative environmental impacts is incorporated into the individual resource-specific discussions, both implicitly (by considering impacts of the Order in the context of environmental conditions that exist because of past and ongoing actions) and explicitly (by considering the potential impacts of any additional ongoing and reasonably foreseeable future actions identified as having the potential to affect the resource).

4.3.1 Air Quality

Impacts to air quality would occur as the result of pollutants being emitted from the Plant's stacks during operations, as well as from activities at the Plant involving vehicle emissions and fugitive dust associated with the coal pile and the handling of ash. The pollutants of primary concern are SO_2 and particulate matter. Modeled concentrations of SO_2 and PM_{10} are discussed in Section 4.3.1.3. All other NAAQS pollutants, including $PM_{2.5}$, and hazardous air pollutants are discussed in Section 4.3.1.5. The emissions from the Plant were modeled for four periods: (1) Pre-shutdown operations, that is, the period before the Plant shutdown in August 2005; (2) Pre-Order operations (Section 4.2.2); (3) the period of the Order, including before

AERMOD

AERMOD is one of the approved models included in EPA's Guideline on Air Quality Models (40 CFR Part 51, Appendix W). It is composed of three parts: AERMAP, AERMET, and AERMOD. AERMOD is a steady-state plume air dispersion model that computes the air concentration of released pollutants at selected receptor points. During each hour modeled AERMOD considers the source characteristics (e.g., amount, temperature, stack exit velocity), atmospheric parameters (e.g., wind speed and direction, atmospheric stability), the relative locations of the source and receptor, and the effects of nearby buildings. The computed hourly concentrations are combined to produce the averaging periods (e.g., 24-hour averages) as requested by the user. AERMAP produces the required input data relative to the receptor grid, including elevation. AERMET processes surface and upper-air atmospheric data and produces the input files required by AERMOD.

[16] Because the Plant was not operating at normal historical levels in the period from August 21-31, 2005, DOE used operational levels for the first 11 days of August 2005 to represent the level that the Plant would likely have operated at if it had been generating power at historical levels during the last 11 days of the month.

the ACO allowed daily predictive modeling (December 20, 2005 through June 30, 2006) and after daily predictive modeling began (July 1 through September 30, 2006); and (4) the period beyond the Order (including the period of the temporary extension of the Order to December 1, 2006) until such time as the new transmission lines are placed into operation (October 1, 2006, through June 30, 2007, or, possibly, December 31, 2007).

4.3.1.1 Modeling methods and assumptions

DOE modeled hourly- and annual-average air concentrations of SO_2 and PM_{10} using the AERMOD system (EPA 2002). (See text box.) AERMOD was used to calculate concentrations for each of the more than 1,700 receptor locations provided by EPA, as shown in Figure 4.3.1-1. The modeled receptor locations include 50-meter intervals along the Plant's fence line. Beyond the fence line, the receptor grid forms a rectangular pattern with the innermost receptors spaced at 100-meter intervals out to a distance of 1,000 meters from the Plant (i.e., the innermost

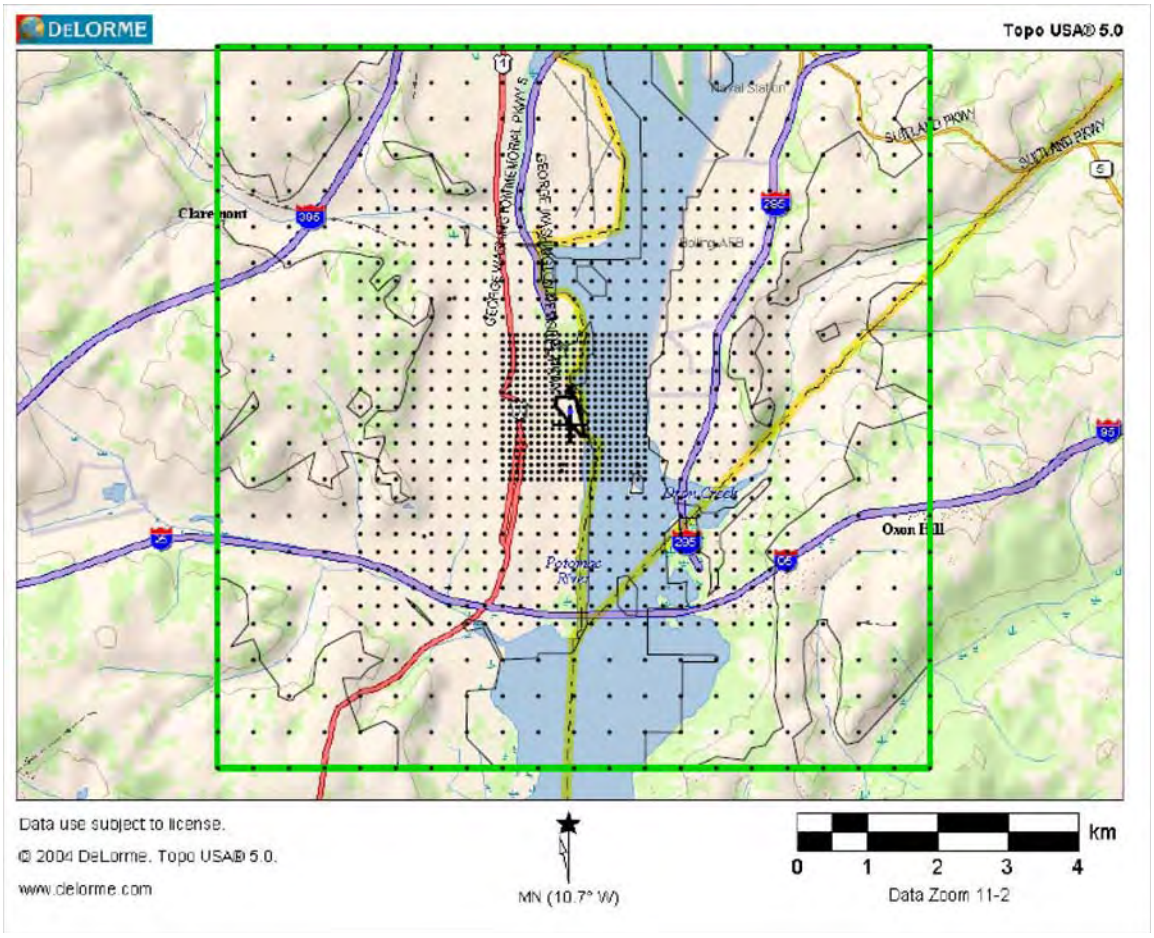


Figure 4.3.1-1. Map of receptor grid points for atmospheric dispersion modeling.

receptor grid forms a square 2,000 meters long on each side). A second set of receptors is located on the rectangular coordinates at 250-meter spacing for the distances between 1,000 and 3,000 meters of the Plant. Beyond 3,000 meters from the Plant, the receptor grid spacing is increased to 500-meter intervals. The receptor farthest from the Plant in an east-west direction (or in a north-south direction) is located 5,000 meters from the Plant. In addition to the grid of receptor locations, DOE modeled pollutant concentrations at several tall buildings in the vicinity of the Plant. DOE modeled 336 points around Marina Towers at the north end of the Plant, as well as points at multiple heights for six other nearby, tall buildings. The 336 points around Marina Towers are from 24 locations around the perimeter of the building and each of 24 floors of the building. Similarly, the multiple heights at the six other nearby buildings are the heights of each floor of the building.

AERMOD input data. For the period December 20, 2005, through March 31, 2006, DOE used actual unit-by-unit emissions (as provided by Mirant) and actual weather data obtained for Ronald Reagan Washington National Airport. These actual emissions and weather data were used in AERMOD to calculate local air pollution contributions of the Plant. For all other time periods DOE used estimated emissions and weather data from 2001 (as provided by EPA). Previous analyses by EPA had shown that 2001 resulted in predictions of more adverse air quality than the other years in the period 2000 through 2004.

For the period April 1 through May 31, 2006, DOE assumed that the Plant operated a different pair of units each week. Mirant reported to DOE that it had identified 10 two-unit operating modes (i.e., combinations of units that could operate for specified numbers of hours per day at specified SO_2 emission rates) that modeling by Mirant's contractor had demonstrated would not lead to exceedances of the 24-hour average SO_2 concentration at any location. For modeling purposes DOE assumed that the Plant practiced a ten-week rotation during which two of the five units were in operation during any given week. DOE assumed the following rotation of units: 1 and 2, 1 and 3, 1 and 4, 1 and 5, 2 and 3, 2 and 4, 2 and 5, 3 and 4, 3 and 5, and 4 and 5.

For the period April 1 through May 31, 2006, DOE assumed that the Plant operated a different pair of units each week. Mirant reported to DOE that it had identified 10 two-unit operating modes (i.e., combinations of units that could operate for specified numbers of hours per day at specified SO_2 emission rates) that modeling by Mirant's contractor had demonstrated would not lead to exceedances of the 24-hour average SO_2 concentration at any location. For modeling purposes DOE assumed that the Plant practiced a ten-week rotation during which two of the five units were in operation during any given week. DOE assumed the following rotation of units: 1 and 2, 1 and 3, 1 and 4, 1 and 5, 2 and 3, 2 and 4, 2 and 5, 3 and 4, 3 and 5, and 4 and 5.

For the month of June DOE assumed that two units at a time operated according to the schedule of allowed operations given in the ACO (Section 4.1.2). DOE assumed that the Plant used each of the 10 combinations of two units and operated each for three days.

DOE assumed that daily predictive modeling, as authorized by the ACO, was implemented beginning July 1, 2006. For operations under daily predictive modeling DOE assumed that, except during outages, each Plant unit generated power at the same level as it had during the year before Mirant terminated operations in August 2005[17] and that at all times Mirant injected enough trona to achieve 50% SO_2 removal (i.e., controlled to 0.525 lb/MBtu). DOE estimated 50% SO_2 removal to be an average or typical removal rate. At low power generation times and/or favorable wind conditions, very little SO_2 removal is needed to meet air quality standards. During high generation times and/or unfavorable wind conditions, higher rates of trona use (to remove up to 80% of SO_2) are necessary to meet air quality standards. DOE selected the assumption of 50% removal as a mid-range value.

During the transmission line outages planned by Pepco (Table 1.3-1), DOE assumed that all five units operated as necessary to meet the full load of Central D.C. as determined from past data.[18] DOE assumed that after a planned transmission outage the Plant resumed generating power at the level it had the year before operations were terminated on August 24, 2005.

The greatest modeled exceedances of the NAAQS SO_2 limits occur during line outage periods. Although removal of 80% of SO_2 from stack gases, which is technically feasible, would considerably reduce (but not eliminate) modeled exceedances, DOE's modeling of line outage periods assumes that the Plant removes 50% of SO_2 from stack gases. DOE has not modeled 80% removal because Mirant does not stockpile sufficient trona to maintain 80% SO_2 removal for an extended (typically, two-week) line outage.

Sulfur Dioxide. The SO_2 modeling proceeded by using AERMOD to calculate concentrations for each receptor grid point. To simulate the daily predictive modeling process of adjusting planned operations until modeled NAAQS compliance is achieved, DOE examined the 24-hour average concentration for each receptor grid point and for each day. For each day the predicted pollution concentration of each point in the receptor grid was reduced by the percentage that just brought the point with the highest concentration into compliance with the 24-hour SO_2 NAAQS limit.[19] DOE performed this procedure for every modeled day (except

---

[17] Mirant provided unit-by-unit, hour-by-hour generation data for the period September 1, 2004, through August 31, 2005. DOE used this hourly power generation data to represent what the Plant would do if there were no environmental constraints. Plant operations were terminated on August 24, 2005. Because the data suggest that the Plant started reducing operations on August 21, generation data after August 20 were not considered representative of normal operation.

[18] During outages, DOE assumed that all five units operate at all times, each generating at least 30 MW (minimum capacity), for a total of at least 150 MW. When the load exceeded 150 MW but did not exceed 366 MW, DOE assumed that the two load-following or cycling units (Units 1 and 2) operated at minimum load (for a total of 60 MW) and the three baseload units (Units 3, 4, and 5) each operated at the same level to meet the remaining load. When the load exceeded 366 MW, DOE assumed that the baseload units each operated at capacity (102 MW), for a total of 306 MW, and the load-following or cycling units each operated at the same level to produce enough additional power to meet the demand until the load exceeded the capacity of the Plant (482 MW).

[19] Compliance with the 24-hour SO_2 limit was based on a concentration of 314 $\mu g/m^3$ (the NAAQS standard

(continued...)

during outages) before calculating 3-hour, 24-hour, and long-term average concentrations. Although the ACO also requires modifying planned operations if daily predictive modeling forecasts an exceedance of 3-hour average SO_2 limits, DOE did not simulate predictive modeling for the 3-hour standard because the computational effort required to calculate average concentrations for all possible 3-hour periods for each of the 1,747 modeled locations was judged to be excessively large for the information to be gained.

Particulate Matter. DOE's modeling considered both stack emissions and fugitive emissions from the Plant as sources of airborne particulate matter.

Based on particulate emissions testing by TRC Environmental Corporation (2006), DOE used a stack emission rate of 0.019 lb PM_{10} per MBtu when trona injection was employed and 0.035 lb/MBtu PM_{10} when it was not in use. For operations before the Order and during the January 2006 transmission line outage, DOE assumed the 0.035 lb/MBtu PM_{10} emission rate. For all other periods after the Order, DOE assumed the 0.019 lb/MBtu emission rate. DOE modeled stack emitted PM_{10} emissions using the same operational schedule as used for SO_2 modeling. However, DOE did not simulate the effects of daily predictive modeling on PM_{10} emissions because DOE found that with the 0.019 lb/MBtu emission rate, stack emissions never lead to exceedances of the NAAQS limit for PM_{10}.

DOE modeled fugitive PM_{10} emissions using fugitive dust parameters supplied to EPA by Mirant. Some fugitive emissions are related to wind; for example, wind blows dust off the coal pile. Most of the emissions are related to the handling of coal and ash, which are operations that increase as plant operations increase. Fugitive dust modeling parameters were not, however, increased or decreased as generating levels increased or decreased. The parameters are based on the assumption that four of the five units operate full time, but they do not account for the extra dust generated by disposal of trona waste.

4.3.1.2 Uncertainties in modeling

The modeling results need to be interpreted cautiously because of many uncertainties related to assumptions and modeling approaches. Overall, DOE's approach was conservative in that it tends to overestimate impacts. Specific sources of uncertainty include the following:

1. DOE chose to use 2001 weather data because, based on EPA experience using 2000 through 2004 weather data, the 2001 data were more likely than other years to yield modeled exceedances.

2. For periods after June 30, 2006, DOE assumed that Mirant used trona injection to reduce SO_2 emissions by 50%. The Plant may operate with less than 50% SO_2 removal when

[19] (...continued)
of 365 less the assumed background concentration of 51 µg/m^3).

modeling (based on predicted weather conditions) does not indicate an exceedance would result. Conversely, the Plant may remove more than 50% of SO_2 or reduce power generation rates when modeling indicates this is necessary to avoid exceedances of the NAAQS. The assumption of 50% SO_2 removal is likely to mean that DOE's modeling underestimates the period-average concentrations of SO_2. However, because of the way DOE has modeled daily predictive modeling, this should introduce little error in estimates of maximum short-term SO_2 concentrations.

3. DOE did not model all of the operational possibilities available to Mirant. When modeling indicates an exceedance, DOE's modeling assumes that Mirant reduces emissions to a level just below what would cause a modeled exceedance. (This is equivalent to assuming that the power generation from each boiler is reduced by the necessary percentage, or that additional trona is injected at each boiler to reduce SO_2 emissions by that percentage.) While it is mathematically possible to exactly meet the 314-µg/m^3 24-hour limit, DOE expects Mirant to keep SO_2 emissions somewhat below the levels that are computed to just meet the limit. Therefore, this DOE modeling approach tends to overestimate actual 24-hour averages.[20]

4. The ACO requires Mirant to achieve 80% SO_2 removal during line outage situations unless predictive modeling demonstrates that this level of SO_2 removal is not necessary or Mirant demonstrates that 80% removal is not "logistically feasible." Because Mirant does not have the capacity to stockpile sufficient trona for an extended line outage, DOE assumed 50% SO_2 removal during line outage situations.

5. DOE has used an estimate of fugitive PM_{10} emissions that is based on the assumption that four of the five boiler units are operating at all times. While some fugitive emissions are caused by wind-blown erosion (e.g., of the coal pile), most fugitive emissions result from coal and ash handling. Because the amount of coal and ash handling is related to the level of power generation, fugitive emissions are probably overestimated for periods when the Plant is producing relatively little power. On the other hand, because the fugitive emissions rates do not account for increased emissions due to trona waste generated by operations, the fugitive emissions may be underestimated during high power generation periods.

6. DOE's modeling of operations under daily predictive modeling does not account for the use of monitoring and alarms to prevent exceedances of SO_2 NAAQS. The ACO requires

[20] Although not required, Mirant is known to be targeting 200 µg/m^3 for a margin of predictive modeling to provide a margin of safety. (D. Lohman, EPA Region 3, personal communication with Seema Kakade, DOE, October 26, 2006.)

Mirant to monitor SO_2 at two locations on the top of Marina Towers and four other locations near the Plant. The ACO requires Mirant to maintain alarms that alert the Plant operators if monitored average concentrations reach 80% of the standards for SO_2. If one of the alarms sound, Mirant is required to modify operations to prevent an exceedance. (See Appendix B, Section IV, B, 5.) Because DOE's modeling does not account for use of monitoring to constrain operations, it overestimates the actual concentrations that will be observed during operations after this section of the ACO takes effect.

7. The highest modeled SO_2 concentrations occur at the rooftop at Marina Towers. Initial monitoring data collected by SO_2 monitors installed by Mirant for the MES do not show concentrations as high as calculated by Mirant's follow-up modeling, which is based on actual weather data. Because DOE believes it used the same AERMOD input parameters that Mirant used, these data suggest that the DOE application of AERMOD may overestimate maximum concentrations at Marina Towers. These data and the questions they raise are described in more detail in Section 4.3.1.4.

Despite the limitations, the results presented here are the best estimates available at this writing.

4.3.1.3 Modeling results for SO_2 and PM_{10} emissions

The EPA has established air quality standards for different averaging periods. An area is considered to be in attainment when the standards are not exceeded at any location in the area. For most pollutants compliance is determined by the second highest value or some other statistical characteristic per year.

The tables in this section present concentrations for three time averaging periods: 3-hour, 24-hour, and specific indicated time periods ranging from 21 to 387 days in length, which are presented as surrogates for the annual average. Although the standards typically determine compliance by the second highest value or another statistical characteristic, for simplicity DOE presents only the highest value for the specified averaging period. This maximum value is likely to be higher than the value used to determine compliance with the standard.

In all cases the value presented in the table is the modeled value for the receptor location that had the highest modeled value among the 1,747 modeled receptor locations. The 3-hour average refers to the highest average concentration for any three consecutive hours for any location. The 24-hour average is the highest average concentration for any calendar day (in the period) at any location. The maximum 3- and 24-hour averages represent relatively unusual occurrences. The annual or period average is more indicative of the usual air quality. Because most of the modeled periods are shorter than one year, the modeled period averages in the tables are not directly comparable to the annual air quality standards, but they do indicate how the period contributes to the annual average. For example, operations during a period with an average that exceeds the annual standard could contribute toward an exceedance of the annual

standard, while operations during a period with an average below the standard could contribute toward meeting the annual standard. Note that, because pollutants are not evenly distributed across the area, all values in the tables considerably overstate the expected concentration at all but a few of the 1,747 modeled locations.

Table 4.3.1-1 shows modeled SO_2 and PM_{10} concentrations for pre-shutdown operations, pre-Order operations, and operations under the Order through September 30, 2006. The first row of the table presents maximum background concentrations. These are the maximum values observed at nearby ambient air quality monitoring stations for the specified averaging periods (Table 3.1-2). The ACO specifies that these "background concentrations" must be added to modeled concentrations resulting from Plant operations in determining whether a "modeled exceedance" occurs. Other rows in the table present modeled concentrations resulting from Plant operations and summed values in which modeled concentrations are added to the maximum background concentrations. The summation approach specified in the ACO is conservative because it is very unlikely that maximum Plant-induced concentrations would occur at the same time as maximum background concentrations. The modeling results presented in the table are discussed in more detail in the following paragraphs.

Pre-shutdown operations. Until August 2005 the Plant operated in the historical manner; essentially, it produced power as economics would dictate. The Plant operated without controls on SO_2 emissions. Table 4.3.1-1 shows that modeling of pre-shutdown operations predicts significant exceedances of the NAAQS for SO_2 concentrations. The table also shows exceedance for the maximum 24-hour PM_{10} concentration. The maximum PM_{10} values reported here are dominated by fugitive dust emissions. Maximum modeled concentrations of PM_{10} from stack emissions are generally less than half of concentrations due to fugitive emissions.

Pre-Order operations. During the fall of 2005, the Plant operated in an 8-8-8 mode: 8 hours off, 8 hours at minimum power, and 8 hours at up to maximum power each day (Section 4.2.2). During this period the Plant was experimenting with trona injection and use of Colombian coal. However, Mirant had performed modeling that showed that no exceedance of the NAAQS SO_2 limit would occur under 8-8-8 operation even if no SO_2 control were employed. Consequently, during this period Mirant did not control SO_2 emissions to any set level. Table 4.3.1-1 shows the results of modeling pre-Order operations for an assumed full year. The table shows that pre-Order operations allow the Plant to meet SO_2 limits.

During 2005 and 2006, Mirant implemented several fugitive dust control measures (Section 2.5). Modeling of PM_{10} concentrations resulting from pre-Order operations used emissions factors that assume that some of these measures were in place. Table 4.3.1-1 shows that modeled PM_{10} concentrations for pre-Order operations are substantially lower than for pre-shutdown operations and meet the PM_{10} limits.

Table 4.3.1-1. Modeled maximum ambient SO_2 and PM_{10} concentrations ($\mu g/m^3$) for Plant operations among all receptor locations.

	SO_2			PM_{10}	
Operating Scenario and Period	**Maximum 3-hour average**	**Maximum 24-hour average**	**Maximum period average (for the specified period or 1 year)**	**Maximum 24-hour average**	**Maximum period average (for the specified period or 1 year)**
Maximum Background Concentration	238 [a]	51 [a]	16 [a]	45 [a]	21 [a]
Modeled Maximum Concentrations					
Pre-shutdown operations (Sep. 1, 2004 through Aug. 20, 2005)	5,156	2,967	299	150	25
Pre-Order operations (annual)	767	277	24	61	13
Dec. 20, 2005 through June 30, 2006					
Non-outage periods (172 days)	479	246	32	36	9
Outage periods (21 days)	3,484	1,888	389	43	13
July 1 through September 30, 2006	1,445	314	136	58	10
Modeled Maximum Concentrations with Maximum Background Concentrations Added					
Pre-shutdown operations (Sep. 1, 2004 through Aug. 20, 2005)	5,394	3,018	315	195	46
Pre-Order operations (annual)	1,005	328	40	106	34
Dec. 20, 2005 through June 30, 2006					
Non-outage periods (172 days)	717	295	48	81	30
Outage periods (21 days)	3,772	1,939	405	88	34
July 1 through September 30, 2006	1,683	365	152	103	31
NAAQS limit [b]	***1,300***	***365***	***80***	***150***	***50***

Note: Modeled values are the highest criteria pollutant concentration among all receptor locations. Pre-shutdown and pre-Order operations do not include higher levels of operations for line outages. Actual or planned line outage conditions are included in the operational periods of the Order. Annual values for modeled concentrations for periods less than one year are time-weighted averages. Whereas many NAAQS limits are specified as the second highest or other value, the modeled values presented in this table are the highest values.

[a] These are the highest values observed at nearby monitoring stations for the specified averaging periods. At most times ambient concentrations are lower than these values. Annual SO_2 concentration is the annual arithmetic mean for years 2001, 2002, and 2003 measured at 517 N. Saint Asaph Street, Alexandria City (ENSR Corporation 2005). Annual PM_{10} concentration is the 2004 arithmetic mean reported in VDEQ 2005, page 49, monitoring site L-46-B3. (Just before publication of this document, Virginia released ambient air monitoring data for 2005 [VDEQ 2006c]. The updated background levels vary only slightly from the 2004 values reported and used here.)

[b] NAAQS values from 40 CFR Part 50. See Section 3.1.2 and Table 3.1-1 for an explanation of NAAQS and the averaging periods that apply to each. EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM_{10} standard, effective December 18, 2006.

Operations under the Order. Operations under the Order were addressed in two periods, December 20, 2005, through June 30, 2006, and July 1 through September 30, 2006. Operations under the Order were divided in this manner because DOE assumed that operations changed significantly when Mirant began operations under daily predictive modeling as permitted by the ACO. The following paragraphs discuss the effects of SO_2 and PM_{10} emissions for these two time periods.

December 20, 2005, through June 30, 2006. For the December through June period, maximum modeled SO_2 concentrations (Table 4.3.1-1) show exceedances of the SO_2 limits during the January line outages, when the highest modeled 3- and 24-hour SO_2 concentrations occurred. For most of the outage trona injection was available on only one unit; Mirant injected trona in two units simultaneously during the last week of the outage. For non-line outage periods through June 30, there were no modeled exceedances of the 3- or 24-hour limits, in part because the Plant operated at a relatively low average power. Table 4.3.1-1 shows no modeled exceedances of limits for PM_{10} during either line outage or non-line outage periods. The fugitive dust parameters used in modeling PM_{10} concentrations for this time period reflect the progressive implementation of fugitive dust control measures at the Plant.

July 1 through September 30, 2006. The commencement of *daily predictive modeling* on July 1, 2006, approximately coincided with the beginning of the season of highest power demand (Figure 4.2-1). Beginning July 1, 2006, modeled plant generation increased and modeled SO_2 exceedances occur for all averaging periods except the 24-hour average during non-outage periods. The ACO requires modifying planned operations if daily predictive modeling forecasts an exceedance of either 3- or 24-hour average SO_2 limits. DOE's modeling assumed that the Plant would scale back operations to meet the 24-hour SO_2 standard as required by the ACO (Section 4.1.2). However, as described in Section 4.3.1.1, DOE's model did not assume that the Plant would scale back operation to meet the 3-hour standard, even though it is required by the ACO, because it would have been excessively complex to model. In actuality, it is expected that the modeled maximum 3-hour average exceedances indicated by Table 4.3.1-1 for the July through September period would be prevented by daily predictive modeling. However, the model's prediction of exceedances when the 3-hour limit is not applied suggests that controlling operations for 24-hour averages is not enough to assure compliance with the 3-hour average SO_2 limit.

The modeled exceedance of the longer-period average SO_2 limit (Table 4.3.1-1) is a logical consequence of operations under daily predictive modeling, because daily predictive modeling allows the Plant to operate at the highest levels that do not cause exceedances of 24-hour SO_2 limit. Operating close to the 24-hour limit (314 g/m^3) day after day inevitably raises the long-term average to a higher level than for a plant that does not consistently operate close to the limit.

The exceedances indicated in the table are modeled exceedances, not actual exceedances. The ACO has provisions for preventing actual exceedances during non-outage periods. In particular, the ACO requires Mirant to monitor SO_2 concentrations near the top of Marina Towers (where the maximum modeled exceedances occur) for close approaches to NAAQS SO_2 limits. If a monitored concentration exceeds 80% of the limit for one of the averaging periods, an audible alarm will sound in the control room (Section 4.1.2.1) and the ACO requires Mirant to take corrective action, such as reducing power generation. Consequently, DOE anticipates that actual exceedances of the SO_2 limits will not occur during non-line outage periods.

As shown by Table 4.3.1-1, Plant operations under the ACO do not result in modeled exceedances of any of the NAAQS limits for PM_{10}.

Operations during a potential extension of the Order until new transmission lines are installed. Table 4.3.1-2 presents modeled maximum concentrations of SO_2 and PM_{10} due to Plant operations during a potential 9- or 15-month extension of the Order beyond September 30, 2006. This includes the period of the temporary 2-month extension of the Order from October 1 to December 1, 2006. Pepco's current schedule has the new transmission lines being installed and operational by the end of June 2007. Because there is a possibility that the transmission lines may not become operational on schedule, DOE has also examined a scenario for extension of the Order through December 2007.

As shown by Table 4.3.1-2, compliance with the ACO leads to meeting the NAAQS limits for 24-hour average SO_2 concentrations during non-line outage periods. As with operations under the initial term of the Order, DOE's model did not assume that the Plant would scale back operation to meet the 3-hour standard as required by the ACO. In actuality, it is expected that the modeled maximum 3-hour average exceedances indicated by Table 4.3.1-2 would be prevented by daily predictive modeling. The modeled exceedances of the NAAQS SO_2 limits for the annual average during non-line outage situations shown in Table 4.3.1-2 result from the assumption that the Plant operates close to the 24-hour limit on a continuing basis. Under the ACO Mirant would be required to modify Plant operations to avoid predicted exceedances of all SO_2 NAAQS averaging periods. Consequently, DOE anticipates that actual exceedances of the SO_2 limits would not occur during non-line outage periods.

As shown by Table 4.3.1-2, Plant operations under an extension of the Order would not result in modeled exceedances of any of the NAAQS limits for PM_{10}.

EPA has provided DOE with preliminary data on monitored air quality measurements taken by Mirant pursuant to the ACO. Mirant sent this information to EPA as part of its monthly reporting requirements under the ACO. EPA is currently reviewing and interpreting the data; however, as discussed in Section 4.3.1.4, the data suggest that actual air quality impacts from operation of the Plant under daily predictive modeling are lower than impacts predicted through DOE's modeling efforts.

4.3.1.4 Monitored SO_2 data

Pursuant to the requirements for performing the MES (Appendix B, Section VI), Mirant has installed six SO_2 monitoring stations near the Plant. Two are located on the roof of Marina Towers--one at the center of the building and one on the southeast wing. One station is located east of stack 5 on the west bank of the Potomac River. Another monitor is located southeast of the Plant along the fence line near the River. One monitor is located at Daingerfield Island about 800 m north of Marina Towers. One monitor is located on the roof of Harbor Terrace (Holiday Inn) southwest of the Plant. These monitoring sites were selected based on discussions among Mirant, DOE and EPA modeling and meteorological experts.

Initial results from the monitors show that actual monitored daily average (approximately the same as 24-hour average) values are much lower than shown by Mirant's follow-up modeling using actual hourly emissions and exhaust parameters and observed weather

Table 4.3.1-2. Modeled maximum ambient SO_2 and PM_{10} concentrations (µg/m^3) for Plant operations among all receptor locations for a potential extension of the Order.

	SO_2			PM_{10}	
Operating Scenario and Period	**Maximum 3-hour average**	**Maximum 24-hour average**	**Maximum period average (for the specified period or 1 year)**	**Maximum 24-hour average**	**Maximum period average (for the specified period or 1 year)**
Maximum Background Concentration	238 [a]	51 [a]	16 [a]	45 [a]	21 [a]
Modeled Maximum Concentrations					
Potential extension of the Order Oct. 1, 2006 – Jun. 30, 2007					
Non-outage periods (203 days)	1,236	314	101	61	12
Outage periods (70 days)	2,193	1,152	171	66	13
Potential extension of the Order Oct. 1, 2006 – Dec. 31, 2007					
Non-outage periods (387 days)	1,449	314	115	67	12
Outage periods (70 days)	2,193	1,152	171	66	13
Modeled Maximum Concentrations with Maximum Background Concentrations Added					
Potential extension of the Order Oct. 1, 2006 – Jun. 30, 2007					
Non-outage periods (203 days)	1,474	365	117	106	33
Outage periods (70 days)	2,431	1.203	187	111	34
Potential extension of the Order Oct. 1, 2006 – Dec. 31, 2007					
Non-outage periods (387 days)	1,687	365	131	112	33
Outage periods (70 days)	2,431	1,203	187	111	34
NAAQS limit [b]	***1,300***	***365***	***80***	***150***	***50***

Note: All periods include the period of the two-month temporary extension of the Order from October 1 to December 1, 2006. Modeled values are the highest criteria pollutant concentration among all receptor locations. Planned transmission line outages in preparation for the 230-kV lines are included in the periods. Annual values for modeled concentrations for periods other than one year are time-weighted averages. While, many NAAQS limits are specified as the second highest or other value, the values presented in this table are the highest values.

[a] These are the highest values observed at nearby monitoring stations for the specified averaging periods. At most times, ambient concentrations are lower than these values. Annual SO_2 concentration is the annual arithmetic mean for years 2001, 2002, and 2003 measured at 517 N. Saint Asaph Street, Alexandria City (ENSR Corporation 2005). Annual PM_{10} concentration is the 2004 arithmetic mean reported in VDEQ 2005, page 49, monitoring site L-46-B3. (Just before publication of this document, Virginia released ambient air monitoring data for 2005 [VDEQ 2006c]. The updated background levels vary only slightly from the 2004 values reported and used here.)

[b] NAAQS values from 40 CFR Part 50. See Section 3.1.2 and Table 3.1-1 for an explanation of NAAQS and the averaging periods that apply to each. EPA's October 17, 2006, rule making on NAAQS for particulate matter (EPA 2006j) revoked the annual PM_{10} standard, effective December 18, 2006.

conditions, matched hour for hour. Specifically, for the period June 17 through September 17, 2006, the maximum monitored daily-average concentration for the monitors ranged from 4 to 63 µg/m^3. For the same time period Mirant's follow-up modeling of actual operations using weather data recorded at Ronald Reagan Washington National Airport gave maximum daily-average concentrations that ranged from 25 to 570 µg/m^3. Aside from the specific operations and weather data, follow-up modeling used the same parameters to characterize the Plant as used for the analysis in the SEA and the 2005 downwash study (ENSR Corporation 2005).

The reasons for the discrepancy between monitored and maximum concentrations from follow-up modeling are not apparent. Mirant's technical consultant reports that when modeling uses effective building dimensions derived from a wind tunnel study, the resulting modeled maximum SO_2 concentrations are closer to the monitored concentrations (Personal communication between D. Shea, ENSR Corporation, Welsford, MA, and L.N. McCold, Oak Ridge National Laboratory, Oak Ridge, TN, October 3, 2006), but this modeling approach does not fully account for the discrepancy. An explanation suggested by Mirant's consultant is that AERMOD underestimates the buoyancy of multiple stack plumes when the wind is blowing parallel to the line of stacks. Another possible explanation is that the weather data from National Airport does not precisely match the weather at the Plant. Mirant's consultant reports that wind directions reported at National Airport are often slightly different from those detected at the Plant. Particularly near the Plant, small differences in wind direction can cause large differences in pollutant concentration at any specific point.

The discrepancy between monitoring data and modeled concentrations raises the possibility that the modeled maximum concentrations reported in Tables 4.3.1-1 and 4.3.1-2 of this SEA are unrealistically high for receptor points that are very close to the Plant. However, because DOE used forecasts rather than actual emissions and weather data, the results presented in this SEA are not directly comparable to either the monitoring data or to Mirant's follow-up modeling.

Because the MES may require as much as a year of monitoring data, EPA is not expected to reach a conclusion about the accuracy of the modeled concentrations before late 2007. In the meanwhile, the ACO requires that the Plant be operated to avoid predicted modeled exceedances.

4.3.1.5 Other air pollutants

Contributions to $PM_{2.5}$ pollution. For $PM_{2.5}$ the NAAQS specify a maximum annual average concentration of 15 µg/m^3 and a 98th-percentile 24-hour average concentration of 65 µg/m^3. Regulation of $PM_{2.5}$ is still developing. On October 17, 2006, EPA published new ambient air quality standards for $PM_{2.5}$ in the *Federal Register* (EPA 2006j). The new standards, which take effect December 18, 2006, retain the level of 15 µg/m^3 for the annual average and institute a 35 µg/m^3 24-hour average. State implementation plans (SIPs) for $PM_{2.5}$ are not due to EPA until 2008.

The $PM_{2.5}$ monitor nearest to the Plant is at Aurora Hills Visitor Center (Table 3.1-2), a short distance west of Ronald Reagan Washington National Airport. The 2004 annual average $PM_{2.5}$ concentration measured at Aurora Hills was 14.4 µg/m^3; the 98th-percentile 24-hour average concentration was 35.7 µg/m^3.[21] As noted in Section 3.1.2, the region in which the Plant exists is in nonattainment with the $PM_{2.5}$ standard.

[21] Just before publication of this document, Virginia released ambient air monitoring data for 2005 (VDEQ 2006c). The updated background levels vary only slightly from the 2004 values reported and used here.

There are two important sources of particulate matter associated with the Plant: stack emissions and fugitive dust. Because fugitive dust from the Plant is emitted near ground level, for locations near the Plant fugitive dust is the principal source of ground level $PM_{2.5}$ attributable to Plant operations. Because stack emissions are located far off the ground, they are the most important Plant-related source of particulate matter at nearby elevated receptor locations, specifically near the top of Marina Towers. Because both ground level and elevated concentrations are important, maximum values for each are presented here.[22]

DOE used estimates of PM_{10} concentrations (Section 4.3.1.3) as a basis for estimating $PM_{2.5}$ concentrations. EPA's AP-42 emission factor guidelines (Personal communication between D. Lohman, U.S. EPA, Region III, and L.N. McCold, Oak Ridge National Laboratory, August 28, 2006) applied to wind blown dust indicate that $PM_{2.5}$ is 15% of the PM_{10}. Based on this guidance, DOE assumed that 15% of fugitive PM_{10} was $PM_{2.5}$. The AP-42 factors for the $PM_{2.5}$ fraction of PM_{10} from electric generating units controlled by electrostatic precipitators range between 44% for dry bottom boilers and 76% for over-fire stokers (Personal communication between D. Lohman, U.S. EPA, Region III, and L.N. McCold, Oak Ridge National Laboratory, August 28, 2006). Based on this guidance, DOE conservatively assumed 76% of PM_{10} emitted from the Plant stacks was $PM_{2.5}$.

DOE's analysis considers only directly emitted particulate matter. In addition to $PM_{2.5}$ that is emitted directly as particulate matter, certain chemicals, especially SO_2 and NO_x, are emitted as gases, but form particulate matter after they are released. This source of $PM_{2.5}$ is not included in the air quality analysis because AERMOD does not incorporate a photochemical model that can account for nonlinear chemical reactions. In addition, such a model would require much more extensive atmospheric data than are readily available. However, because the background concentrations used in developing DOE's $PM_{2.5}$ estimates were measured while the Plant was operating at pre-shutdown levels, some, unknown but probably small, fraction of the background is due to Plant operations. Consequently, adding estimated Plant contributions to background concentrations involves some double counting of Plant effects. The discussion below presents estimates of $PM_{2.5}$ contributions first with and then without background concentrations.

Pre-shutdown operations. Pre-shutdown operations (one year) are estimated to have resulted in maximum 24-hour average concentrations of 74 $\mu g/m^3$ (38 $\mu g/m^3$ due to Plant operations alone; that is, without background) at ground level and 112 $\mu g/m^3$ (76 $\mu g/m^3$ due to Plant operations) at the top of Marina Towers. The annual average ground level $PM_{2.5}$ concentration was estimated to be 20 $\mu g/m^3$ (5.7 $\mu g/m^3$ due to Plant operations), and the average annual $PM_{2.5}$ concentration at the top of Marina Towers was estimated to be 22 $\mu g/m^3$ (7.8 $\mu g/m^3$ due to Plant operations).

Pre-Order operations. If pre-Order operations had continued for one year. the maximum estimated ground-level 24-hour-average $PM_{2.5}$ would have been 45 $\mu g/m^3$ (9.2 $\mu g/m^3$ due to

[22] Both stack and fugitive sources were included in estimating $PM_{2.5}$ concentrations for both ground-level and elevated receptors.

Plant operations), and the comparable concentration at the top of Marina Towers would have been 40 $\mu g/m^3$ (4.8 $\mu g/m^3$ due to Plant operations). The maximum estimated ground-level annual average $PM_{2.5}$ concentration would have been 16 $\mu g/m^3$ (2.0 $\mu g/m^3$ due to Plant operations), and the maximum annual average concentration at the top of Marina Towers would have been 15 $\mu g/m^3$ (1.0 $\mu g/m^3$ due to Plant operations).

Operations under the Order. For the duration of the Order, the estimated maximum 24-hour-average ground-level $PM_{2.5}$ concentration is 61 $\mu g/m^3$ (25 $\mu g/m^3$ due to Plant operations), and the maximum estimated ground-level 285-day-period-average $PM_{2.5}$ concentration is 38 $\mu g/m^3$ (2.4 $\mu g/m^3$ due to Plant operations). Because an important fugitive dust suppression measure was implemented in March 2006, the period before April contributed more to the 285-day-period average $PM_{2.5}$ concentration than operations after April, and the maximum estimated 24-hour-average $PM_{2.5}$ concentration occurred before April.

For the duration of the Order, the maximum 24-hour-average concentration at the top of Marina Towers is 76 $\mu g/m^3$ (41 $\mu g/m^3$ due to Plant operations), and the maximum 285-day-period-average concentration at the top of Marina Towers is 18 $\mu g/m^3$ (3.9 $\mu g/m^3$ due to Plant operations). Because of increased generation after the start of operations under daily predictive modeling, operations after June contributed more to the 285-day-period-average $PM_{2.5}$ concentrations than operations before July, and the maximum estimated 24-hour-average concentration occurred after June.

Potential extension of the Order. For a potential extension of the Order through December 2007 (including the period of the temporary extension until December 1, 2006), the estimated maximum 24-hour average ground-level concentration would be 58 $\mu g/m^3$ (23 $\mu g/m^3$ due to Plant operations), and the maximum estimated concentration on the top of Marina Towers would be 79 $\mu g/m^3$ (43 $\mu g/m^3$ due to Plant operations). The estimated maximum 24-hour average occurs during non-outage periods. The estimated maximum annual average ground-level $PM_{2.5}$ concentration would be 18 $\mu g/m^3$ (4.0 $\mu g/m^3$ due to Plant operations), and the estimated maximum concentration at the top of Marina Towers would be 20 $\mu g/m^3$ (5.7 $\mu g/m^3$ due to Plant operations).

Nitrogen oxide contributions to ozone (O_3) pollution. Alexandria and the surrounding area are in nonattainment for O_3. Ozone is formed in the atmosphere when sunlight interacts with NO_x and volatile hydrocarbons. In the eastern United States, natural volatile hydrocarbon molecules are abundant in the atmosphere. Consequently, the most effective method for limiting the formation of O_3 is limiting the abundance of NO_x in the atmosphere. NO_x is readily formed in high temperature combustion processes such as power plants and internal combustion engines.

The following data were used to estimate NO_x emissions. Hourly operations data for December 20, 2005, through March 31, 2006, indicate that average NO_x emission rate for Units 1 and 2 is about 0.35 lb/MBtu and the emission rate for Units 3, 4, and 5 averages 0.26 lb/MBtu. Assuming that each unit consumes the same average amount of coal, the average emission rate would be 0.296 lb per MBtu of coal consumed. At 12,000 Btu/lb of coal, Units 1 and 2 have NO_x

emission rates of 8.4 lb per ton of coal. When all units operate (using equal quantities of coal), the average NO_x emission rate is about 7.1 lb per ton of coal.

As a point of reference, the ACO requires that the Plant emit no more than 3,700 tons (3,400 metric tons) of NO_x per year.

Pre-shutdown operations consumed about 832,000 tons (755,000 metric tons) of coal per year and emitted 3,000 tons (2,700 metric tons) of NO_x per year. For comparison purposes, if pre-shutdown operations had continued for the 285-day duration of the Order, the Plant would have consumed about 650,000 tons (590,000 metric tons) of coal and emitted about 2,300 tons (2,100 metric tons) of NO_x. If pre-shutdown operations were to continue for a 15-month extension of the Order through December 2007 (including the period of the temporary extension until December 1, 2006), the Plant would consume about 1,040,000 tons (943,000 metric tons) of coal and emit about 3,700 tons (3,400 metric tons) of NO_x.

Pre-Order operations. For comparison purposes, if pre-Order operations (when only Unit 1 operated) had continued for the duration of the Order, the Plant would have consumed about 153,000 tons (140,000 metric tons) of coal and emitted about 640 tons (580 metric tons) of NO_x, a rate of about 820 tons (750 metric tons) per year. If pre-Order operations were to continue for an extension of the Order through December 2007 (including the period of the temporary extension until December 1, 2006), the Plant would emit about 1,030 tons (940 metric tons) of NO_x over the 15-month period.

For the 285-day term of *the Orde*r, the Plant is estimated to burn about 566,000 tons (504,000 metric tons) of coal and emit about 2,600 tons (2,300 metric tons) of NO_x, a rate of 2,600 tons (2,300 metric tons) per year.

For *potential extension of the Order* from October 1, 2006 through December 2007 (including the period of the two-month temporary extension until December 1, 2006), the Plant would consume about 1,040,000 tons (940,000 metric tons) of coal and emit about 3,700 tons (3,400 metric tons) of NO_x, a rate of about 3,000 tons (2,700 metric tons) per year.

Contributions to carbon monoxide (CO) and lead pollution. As shown by Table 3.1.2, monitored levels of CO are well below the standard. Because CO levels are so low and because coal-fired power plants are not significant sources of CO, DOE did not model contributions to ambient CO levels due to Plant operations. Because ambient lead concentrations have declined to such low levels since the elimination of leaded gasoline that lead concentrations are no longer monitored in Virginia, DOE did not model potential contributions due to Plant operations.

Contributions to hazardous air pollutants. *Mercury* emissions by coal fired power plants are believed to be a major contributor to atmospheric mercury contamination. In its elemental form mercury is easily vaporized. Mercury forms nonvolatile compounds with sulfur and chlorine that can be captured in precipitators and incorporated in fly ash, but DOE assumed that all mercury in the coal burned by the Plant is emitted to the atmosphere through the stacks. This assumption is not likely to lead to an overestimate of mercury emissions because chemical analyses of Plant fly ash did not detect mercury (Section 4.3.5).

Data provided by Mirant indicates that the mercury content of coal supplied to the Plant ranges from 0.03 to 0.07 ppm (0.06 to 0.14 lb mercury per thousand tons of coal). DOE's analysis conservatively uses the high end of this range, that is 0.14 lb per thousand tons of coal.

Pre-shutdown operations consumed about 832,000 tons (755,000 metric tons) of coal per year. At 0.14 lb of mercury per thousand tons of coal, pre-shutdown operations can be estimated to emit 116 lb/year (53 kg/year) of mercury. For the 285-day period of the Order, it would emit about 91 lb of mercury. For extension of pre-shutdown operations through a 15-month extension of the Order, operations would emit about 145 lb of mercury.

For *pre-Order operations*, the Plant would burn about 540 tons (490 metric tons) of coal per day. Pre-Order operations for the period of the Order would lead to consumption of about 153,000 tons (140,000 metric tons) of coal. At 0.14 lb mercury per thousand tons of coal, pre-Order operations would have caused emission of about 21 lb (10 kg) of mercury for the period of the Order. Pre-Order operations for a 15 month extension of the Order would involve consumption of about 245,000 tons (220,000 metric tons) of coal and emission of about 34 lb (16 kg) of mercury.

For the 285 days of *the Order*, DOE estimates Plant coal consumption at 566,000 tons (510,000 metric tons), resulting in emissions of about 79 lb (36 kg) of mercury. Thus, the Order is estimated to increase mercury emissions of the Plant by 58 lb (26 kg) over the 285-day term of the Order. By comparison, if *pre-shutdown operations* had continued for the same 285 days, the Plant would have consumed about 650,000 tons (590,000 metric tons) of coal and emitted about 91 lb (41 kg) of mercury.

For *potential extension of the Order* from October 2006 through December 2007 (including the period of the two-month temporary extension until December 1, 2006), the Plant would consume about 1,040,000 tons (943,000 metric tons) of coal and emit approximately 146 lb (66 kg) of mercury. By comparison, pre-Order operations of the Plant for the same period would involve burning about 245,000 tons (220,000 metric tons) of coal with emission of about 34 lb (16 kg) of mercury. Thus, extension of the Order for 15 months would result in an increase in mercury emissions, over pre-Order operations, of about 111 lb (50 kg) mercury.

Other metals typically present as trace constituents of coal are less volatile than mercury, so they are primarily incorporated into solid wastes (bottom ash and fly ash), with only small fractions emitted to the atmosphere. The coal data that Mirant provided to DOE did not include concentrations of toxic metals other than mercury. Table 2.3-1 summarizes some published data on concentrations of seven trace metals in Appalachian coals. These data provide an indication of levels that may be present in the central Appalachian coal burned by the Plant. DOE performed a mass balance analysis for five of these metals using data on fly ash from Table 4.3.5-2. The results suggest that much of the arsenic and cadmium in the original coal, and some of the lead, selenium, and chromium are captured in fly ash. Capture of selenium in fly ash increases greatly when trona is used in the Plant (Section 4.3.5). DOE does not have data on the composition of the Plant's bottom ash, which would be expected to contain the majority of some metals, particularly the least volatile, such as beryllium, chromium, and nickel. Metals not

captured in a solid phase are released to the atmosphere. DOE has not estimated the quantities of these metals released to the atmosphere.

4.3.1.6 General conformity requirement

Background. General conformity arises out of Section 176(c)(1) of the Clean Air Act (CAA) which provides that no Federal agency shall "engage in, support in any way or provide financial assistance for, license or permit, or approve, any activity which does not conform to [an approved State implementation plan (SIP)]." Under the CAA conformity to an implementation plan means that such activities will not (1) cause or contribute to any new violation of any standard in any area, (2) increase the frequency or severity of any existing violation of any standard in any area, or (3) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area [CAA §176(c)(1)(B)].

Before DOE issued its Order, VDEQ raised several concerns related to general conformity in its filing to FERC (VDEQ 2005b).[23] VDEQ claimed that resumption of Plant operations at the previous levels would "not be in conformity with the Virginia SIP's purpose of eliminating or reducing the severity and number of exceedances of the NAAQS." VDEQ's filing to FERC also claimed that resumption of Plant operations "at the previous levels, or any other level that would not be protective of human health or the environment, would clearly conflict with Mirant's regulatory obligation to comply with the [VDEQ] Director's request under 9 VAC 5-20-180(I), and therefore would not be in conformity with the SIP."

The Federal general conformity regulations implementing Section 176(c)(1) of the CAA are codified at 40 CFR Part 51, Subpart W, and 40 CFR Part 93, Subpart B. Pursuant to 40 CFR 51.851, Virginia has an EPA approved general conformity rule that complies with the CAA. Therefore, Virginia's general conformity rule applies here.

Under the general conformity rules, if the conformity rule applies to a Federal action, then the agency must determine whether the action "conforms" to a SIP. The conformity rule applies for each pollutant where the total of direct and indirect emissions in a nonattainment or maintenance area caused by the action would equal or exceed de minimis thresholds and where the action does not fit an exception (9 VAC 5-160-30). If the conformity rule applies, a Federal action is deemed to "conform" to a SIP if it is in compliance with all relevant requirements and milestones in the SIP and meets one of several requirements enumerated in the regulations, such as the emissions are specifically identified and accounted for in the SIP (40 CFR 93.158, 9 VAC 5-160-160).

The city of Alexandria and surrounding Arlington, Fairfax, Loudoun, and Prince William counties are in nonattainment for $PM_{2.5}$ and 8-hour ozone (the precursors for ozone are NO_x and volatile hydrocarbons) (EPA 2006f). Because the general conformity regulations only apply to

[23] As stated in DOE's Order (footnote 2), DOE considered all legal arguments made in FERC filings in its decision-making process.

Federal actions that exceed de minimis thresholds in designated "nonattainment" or "maintenance" areas, these are the only pollutants that are relevant here.

The Order conforms to the Virginia SIP. Because the Order does not cause or contribute to new emissions not already accounted for in the SIP or interfere with limits in the SIP, the Order conforms to the Virginia SIP. The Order does not allow the Plant to resume operations at levels it had been operating at under the Virginia SIP before the August 24, 2005, shutdown. Instead, the Order only allows the Plant to operate at pre-shutdown levels in limited transmission line outage circumstances, or when permitted by daily predictive modeling. In addition, for $PM_{2.5}$ the Order cannot interfere with $PM_{2.5}$ emissions not already accounted for in the SIP because Virginia does not currently have a SIP for $PM_{2.5}$.[24] Similarly, because the original study regarding the Plant's NO_x emissions (prompting the shutdown of the Plant on August 24, 2005), related to downwash rather than to NO_x as a precursor to ozone, the Order would not appear to affect Virginia's SIP for ozone (EPA 2006g).[25]

Furthermore, the Order alleviates the concerns related to conformity to the SIP raised by VDEQ in its filing to FERC. To the extent that the SIP accounts for full operation of the Plant without the use of trona and low-sulfur coal, the Order actually decreases emissions already accounted for in the SIP. Therefore, the Order helps Virginia achieve its "purpose of eliminating or reducing the severity and number of exceedances of the NAAQS" (VDEQ 2005b). The Order also does not present a conflict between resumption of Plant operations under the Order and Mirant's regulatory obligation to comply with the VDEQ Director's August 19, 2005, request. Indeed, the VDEQ Director's August 19, 2005, letter to Mirant suggested the "potential reduction of levels of operation" as a potential method of complying with the Director's request under 9 VAC 5-20-180(I) to "immediately undertake such action as is necessary to ensure protection of human health and the environment" (Personal communication between R.G. Burnley, VDEQ, and L.D. Johnson, Mirant Potomac River, LLC., August 19, 2005). Moreover, the DOE Order does not impinge upon VDEQ's ability to enforce concerns over pollutants emitted from the Plant. For example, during the period of the Order, VDEQ continued to work with EPA and Mirant on a long-standing settlement over NO_x that began in 2003 and resulted in an amended settlement on May 8, 2006 (EPA 2006g).

The function of the general conformity requirement is to ensure that Federal actions do not interfere with SIPs for meeting CAA standards and requirements. The integration of Federal actions and state air quality planning is intended to "protect the integrity of the SIP by helping ensure that SIP growth projections are not exceeded, emissions reduction progress targets are achieved, and air quality attainment and maintenance efforts are not undermined" (58 FR 63214,

[24] Although EPA has had a $PM_{2.5}$ NAAQS since 1997 (revised on October 17, 2006), $PM_{2.5}$ SIP's are not due for states with designated nonattainment areas for $PM_{2.5}$ until April 2008 (EPA 2006h, 2006i).

[25] Concerns over alleged violations of the 2003 Ozone Season NO_x emission limitations specified in Mirant's Stationary Source Permit have been resolved through a judicial consent decree between EPA, VDEQ, the State of Maryland, and Mirant (EPA 2004, 2006g).

63215; Nov. 30, 1993). In this case the Order not only conforms to the Virginia SIP by definition, but also achieves the overarching purpose of the general conformity principle.

The Order is exempt under the General Conformity regulations. Even if the Order does not conform to the Virginia SIP, the emissions generated from the Order fall within the "emergency" exceptions enumerated in the Virginia conformity regulations (9 VAC 5-160-30). A conformity determination is not required for "actions in response to emergencies or natural disasters such as hurricanes, earthquakes, etc., which are commenced on the order of hours or days after the emergency or disaster . . ." (40 CFR 93.153(d)2). "Emergency" is further defined in the Federal conformity regulations as:

> A situation where extremely quick action on the part of the Federal agencies involved is needed and where the timing of such Federal activities makes it impractical to meet the requirements of this subpart, such as natural disasters like hurricanes or earthquakes, civil disturbances such as terrorist acts and military mobilizations. (40 CFR 93.152)

An emergency clearly existed on December 20, 2005. In fact, the very nature of DOE's ability to issue the Order in the first place comes from the Department's *emergency* authority under Section 202(c) of the Federal Power Act. It took DOE three months to understand the reliability situation at hand and determine the potential environment, health, and safety risks associated with the Plant's shutdown. However, as soon as a line outage occurred (December 16, 2005) and the very real threat of a blackout in the Central D.C. area became apparent, DOE took quick action by issuing its Order. Therefore, DOE's action qualifies as an emergency exception to the general conformity regulations.

4.3.1.7 Global climate change

A major worldwide environmental issue is the likelihood of major changes in the global climate (e.g., global warming) as a consequence of increasing atmospheric concentrations of "greenhouse" gases (IPCC 2001). The atmosphere allows a large percentage of incoming solar radiation to pass through to the earth's surface and be converted to heat energy (infrared radiation) that does not pass back through the atmosphere as easily as the solar radiation passes in. The result is that heat energy is "trapped" near the earth's surface.

Greenhouse gases include water vapor, CO_2, methane, nitrous oxide, O_3, and several chlorofluorocarbons. The greenhouse gases constitute a small percentage of the earth's atmosphere; however, their collective effect is to keep the temperature of the earth's surface about 60°F (33°C) warmer, on average, than it would be if no atmosphere existed. Water vapor, a natural component of the atmosphere, is the most abundant greenhouse gas. The second-most abundant greenhouse gas is CO_2, which has increased about 30% in concentration over the last century. Fossil fuel burning is the primary contributor to increasing concentrations of CO_2 (IPCC 2001). The increasing CO_2 concentrations likely have contributed to a corresponding increase in

globally averaged temperature in the lower atmosphere, which has increased by about 1–1.4°F (0.5-0.8°C) in the last hundred years (IPCC 2001).

Because CO_2 is relatively stable in the atmosphere and essentially uniformly mixed throughout the troposphere and stratosphere, the climatic impact of CO_2 emissions does not depend upon their source location on the earth. Instead, an increase in CO_2 emissions from a specific source is effective in contributing to global increases in CO_2 concentrations.

Carbon dioxide emissions from the Plant involve two components: CO_2 produced by the combustion of the carbon contained in the coal and CO_2 produced by chemical reactions as the trona removes SO_2 from the exhaust gases. These two components of Plant emissions are shown in Table 4.3.1-3 and are discussed in detail in the following paragraphs. Coal combustion is discussed first.

During four days in December 2005, when the Plant was running in pre-Order mode, the Plant burned 2,150 tons (1,950 metric tons) of coal. This coal produced 5,300 tons (4,800 metric tons) of CO_2. Operation of the Plant for a full year at the pre-Order level operations would be expected to produce about 480,000 tons (440,000 metric tons) of CO_2.

For the 285-day term of the Order (December 20, 2005, through September 30, 2006), the total amount of coal used by the Plant is estimated to be 566,000 tons (513,000 metric tons). This quantity of coal, when burned, would produce approximately 1.38 million tons (1.25 million metric tons) of CO_2. On an annualized basis operation of the Plant under the Order would be expected to produce at an annual rate of 1.76 million tons (1.60 million metric tons) of CO_2 per year.

During the one-year period immediately preceding the shutdown of the Plant in August 2005, the Plant generated power at an average rate of 210 MW, using an estimated 832,000 tons (755,000 metric tons) of coal. The combustion of this amount of coal produced approximately 2 million tons (1.8 million metric tons) of CO_2. These data can be used to represent the anticipated operation of the Plant during the two-month temporary extension until December 1, 2006, and through the duration of any additional extension of the Order (i.e., October 1, 2006, through December 31, 2007).

For all three cases above, the use of trona is assumed to result in 50% removal of SO_2 from the Plant's stack gases. To achieve this removal rate, trona needs to be fed at a 2.5 times higher than the rate theoretically calculated to be sufficient to react with all of the SO_2 in the stack gases. With the addition of heat CO_2 is released from trona in a calcining reaction. This results in approximately 0.009 lb of CO_2 being released from trona for each pound of coal burned. The resulting quantities of the CO_2 released from trona, as shown in Table 4.3.1-3, are a very small fraction of the CO_2 released by coal combustion.

To put the above numbers into perspective, global fossil combustion in the year 2003 resulted in emissions of approximately 28 billion tons (26 billion metric tons) of CO_2 (Marland et al. 2006).

Table 4.3.1-3. Annualized carbon dioxide emissions (tons/year) from the Mirant Plant during operational periods under analysis in this report

	Coal combustion	Trona utilization	Total from Plant
Pre-shutdown operations	2,000,000	0	2,000,000
Pre-Order operations	480,000	1,800	488,800
The Order (Dec. 20, 2005 – Sep. 30, 2006)	1,760,000	6,500	1,766,500
Potential extension of the Order (Oct. 1, 2006 – Dec. 19, 2007)[a]	2,000,000	7,500	2,007,500

Note: "Annualized" values were obtained by prorating the emissions during the actual period over a hypothetical 365-day period.
[a]Includes the period of the temporary extension of the Order until December 1, 2006.

4.3.2 Human Health

This section discusses the human health impacts of emissions from the Plant during two principal time periods: (1) the period of operations under the Order and (2) the duration of a potential extension of the Order. As a comparison, the health effects of the pre-Order mode of operation as well as the pre-shutdown operation of the Plant are also presented. The analysis in this section uses mathematical factors that relate a person's exposure to concentrations of airborne pollutants to premature mortality and other health effects.

Potential human health effects resulting from the Order are a serious concern to DOE. A wide range of human health effects are associated with ambient concentrations of particulate matter and SO_2 as well as other NAAQS primary and secondary pollutants. Numerous epidemiological studies have demonstrated that increases in pollution levels are associated with increases in illness rates, use of health services, and earlier death among exposed persons.[26]

Particle pollution, especially fine particle pollution (i.e., $PM_{2.5}$), contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing,
- decreased lung function,
- aggravated asthma,
- development of chronic bronchitis,
- irregular heartbeat,

[26] Some recent information about air pollution health effects may be found in the Criteria Documents prepared to support EPA periodic reviews of the NAAQS; http://www.epa.gov/ttn/naaqs/.

- nonfatal heart attacks, and
- premature death in people with heart or lung disease.

People with heart or lung diseases, children, and older adults are most likely to be affected by particle pollution exposure. However, even healthy people may experience temporary symptoms from exposure to elevated levels of particle pollution.

Peak levels of SO_2 in the air can cause temporary breathing difficulty for people with asthma who are active outdoors. Longer-term exposures to high levels of SO_2 gas and particles cause respiratory illness and aggravate existing heart disease. SO_2 reacts with other chemicals in the air to form tiny sulfate particles. When these are breathed, they gather in the lungs and are associated with increased respiratory symptoms and disease, difficulty in breathing, and premature death.

4.3.2.1 Analytical approach

For the purposes of this SEA, DOE has used two techniques to estimate premature mortality due to Plant operations and has used one technique to estimate the incidence of other health effects. DOE analyzed all-cause mortality as a useful indicator of health effects because background mortality rates are readily obtainable and the association between air pollution and premature mortality[27] has well-documented response functions. DOE used a concentration-response function for premature mortality from Pope et al. (2002) to estimate the expected fatalities and to estimate the risk of premature mortality to a hypothetical maximally exposed individual in the community near the Plant. DOE used an EPA scaling technique (EPA 2005) to estimate premature mortality and other health effects to a much broader population.

For the assessment of health effects to persons in the local area, DOE used estimated $PM_{2.5}$ and modeled SO_2 concentrations for a 36-mi^2 (93-km^2) receptor grid comprised of 1,747 receptor locations with the Plant near its center (Figure 4.3.1-1). This area contains approximately 240,581 people.[28]

In order to provide estimates of the adverse effects of various operating scenarios in this SEA, DOE has chosen all-cause mortality as the most useful single indicator of adverse health effects. Mortality is the most severe outcome in personal terms and also represents 90% or more of the associated cost in economic terms.

---

[27] The studies on which this environmental analysis is based analyzed all-cause mortality for cohort studies, which capture both short-term and long-term effects. *All-cause mortality* means fatalities that occur for any reason. Scientists studying the effects of air pollution use all-cause mortality rather than fatalities that are clearly tied to air pollution because accurately determining the cause of death is often impossible in epidemiological studies.

[28] The population estimates are based on individual, rectangular cells with a dimension of 15 seconds of one degree on each side. The populations within all such cells within the grid are interpolated to the U.S. Census Bureau's 2005 estimates (Personal communication between P. Coleman, Oak Ridge National Laboratory, and A.L. Sjoreen, Oak Ridge National Laboratory, June 5, 2006).

DOE used the adult (age 30 and older) $PM_{2.5}$ concentration-response function (relative rate: 1.06 per 10 µg/m^3, 95% confidence interval: 1.02–1.11) from Pope et al. (2002).[29] The Pope et al. (2002) study finds one of the strongest associations between $PM_{2.5}$ exposure and premature mortality. Because SO_2 represents a significant proportion of the Plant's pollutant output, and SO_2 is known to convert to sulfate particles in ambient air, it is considered here as an addition to the estimated $PM_{2.5}$ concentrations.[30] DOE assumed that SO_2 converts to sulfate particles as an addition to the $PM_{2.5}$ loading at the rate of 7% per 24-hour period (Azad and Kitada 1998).

All cause premature mortality is calculated by multiplying the modeled pollutant concentration by the age specific population, the age specific all-cause death rate, and the concentration-response function to obtain the expected number of deaths. Sixty percent of the population in Virginia is aged 30 or older (Virginia Department of Health 2004). For the receptor grid DOE studied this yields an estimate of 144,000 persons 30 or older. For this age group, the annual, all-cause death rate is 13 per 1,000 (Virginia Department of Health 2004).

To estimate several other health effects from particulate matter resulting from plant operations, DOE used a scaling technique developed by EPA based on extensive air quality modeling (EPA 2005). The method involves interpolation among cases that were modeled in detail by EPA. DOE used parameters provided by EPA to estimate health effects incidence based on total emissions of SO_2, NO_x, and $PM_{2.5}$ from the Plant (Personal communication between B. Hubbell, EPA, and L.N. McCold, Oak Ridge National Laboratory, October 11, 2006). The potentially affected population on which these estimates are based is roughly the population of the eastern United States. While the risks to persons who live near the Plant are largest, the expected incidence includes the sum of very small risks to millions of people.

4.3.2.2 Results

DOE estimated the expected incidence of premature mortality among the 144,000 adult population (age 30 or older) in a 36-mi^2 (93-km^2) area centered on the Plant (Figure 4.3.1-1). The results of the analysis of health effects to the adult population are described by the following bullets:

- As a result of exposure to the combined effects of SO_2 and PM_{10}, the expected incidence of premature mortality among the 144,000 adults (30 and older) in a 36-mi^2 (93-km^2) area around the Plant from *pre-shutdown operations* is about 3.8 (confidence interval: 1.2 to 6.8) per year.

[29] EPA employs the Pope et al. $PM_{2.5}$-related mortality estimates as one component in cost/benefit analyses of various air pollution reduction strategies (EPA 2005). Information on EPA's studies and the methodology can be found in the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (EPA-452/R-05-002, March 2005), which may be found at http://www.epa.gov/air/interstateairquality/pdfs/finaltech08.pdf.

[30] NO_x is also known to convert to $PM_{2.5}$ in the atmosphere. DOE did not include NO_x in the analysis of nearby health effects because NO_x is a relatively smaller part of Plant pollution emissions and converts to $PM_{2.5}$ less efficiently that SO_2.

- For *pre-Order operations,* the expected incidence of premature mortality among the exposed population of 144,000 adults (30 and older) would be 0.77 (confidence interval: 0.26 to 1.4) per year.
- For *operations under the Order* the expected incidence of premature mortality among the adult population of 144,000 is 1.3 (confidence interval: 0.44 to 2.4). The annual rate for operations under the Order is 1.7 (confidence interval: 0.58 to 3.1).
- For *potential extension of the Order* through June 2007 the expected incidence of premature mortality among the adult population of 144,000 would be 1.5 (confidence interval: 0.51 to 2.7) Extending it through December 2007 would raise the expected fatalities to 2.9 (confidence interval: 0.97 to 5.1). The annual rate for extension of the Order is 2.3 (confidence interval 0.78 to 4.1).

Statistical Terminology

The results of the health effects analysis are expressed in statistical terms.

Some results are expressed as the ***expected incidence*** of a specified health effect occurring in the exposed population. For instance, if pepper were thrown into the faces of 1,000 people in 100 groups of 10 people and 340 of the people sneezed, for the next randomly selected group of 10 people, the expected incidence of sneezing would be 3.4 people. In each group of 10, the number of people sneezing would be a whole number. Sometimes it would be three people, sometimes it would be four, and it could as small as zero or as a high as 10, but for this hypothetical example the long-term average would be 3.4. Expected incidence, in this case 3.4, is not a statement about what will occur, but a statement of what is likely to occur.

Other results are expressed as the ***probability*** that an individual who is exposed would experience the specified health effect. For the example above, the probability that any one random individual would sneeze would be 0.34 (=340/1000).

Another example shows how probability statements can be interpreted for groups and individuals. In 2003 approximately 25 per 100,000 (0.00025 or 0.025%) Americans 50 years of age or older, were diagnosed with stomach cancer. This can be reported as an expected incidence of 25 stomach cancers per 100,000 Americans age 50 or older. For an average American 50 or older, the probability per year of being diagnosed with stomach cancer is 0.00025.

The reader should understand that the estimates of expected fatalities above do not indicate the risk faced by any particular individual. Pollutants do not affect all sectors of the population to the same extent. The very young, the elderly, and those with preexisting health conditions tend to experience adverse health effects at pollutant levels that have little or no effect on the remainder of the population. Activity levels also affect the nature of the health effects; the more active the person, the more likely that PM or SO_2 will induce health effects. For instance, jogging while pollution levels are high is more likely to cause health effects in healthy people than would resting on a picnic bench or walking slowly. The reader should also bear in mind that among the modeled population of 144,000 adults, about 1,800 would die each year due to various causes.

Another useful indicator of the potential health effects of the Order is the risk to the "maximally exposed individual." The maximally exposed individual is a hypothetical person who spends all his time outdoors at the receptor point that has the highest average modeled concentration. Nobody stays at the same place all the time, so the maximally exposed individual establishes the upper limit on the health risk that anyone could experience. However, the response factor used to generate these estimates is for the average adult (30 or older). Persons who are more susceptible to air pollutants would have a higher risk and healthy people would have a smaller risk.

Confidence Intervals

A confidence interval is one expression of the uncertainty associated with a statistical estimate. To be clearly defined, the confidence interval needs to specify the confidence level associated with the interval. The confidence intervals reported in this SEA are for a 95% confidence level. For example, if the estimate of the probability of a health effect is 0.30, it means that the best estimate of the probability is 0.30. If the associated 95% confidence interval is 0.17 to 0.48, it means that while the estimate is not certain, we are 95% confident that the true probability of the health effect is no lower than 0.17 and no higher than 0.48.

A confidence interval is helpful in informing us of how much confidence we can have in a statistical estimate. For example, if the confidence interval above were 0.29 to 0.31, we would know that we could be very confident in the estimate of 0.30. Conversely, if the confidence interval were 0.01 to 0.99, we would know to have much less confidence that 0.30 was close to the true value.

- For *pre-shutdown operations* the hypothetical maximally exposed individual has a risk of premature mortality of 0.22% (confidence interval: 0.074 to 0.39%) for a year of operation.
- For *pre-Order operations* if they had continued for one year, the risk of premature fatality to the hypothetical maximally exposed individual would be 0.028% (confidence interval: 0.0094 to 0.050%)
- For *operations under the Order* the risk of premature mortality from SO_2 concentrations to the maximally exposed individual is 0.072% (confidence interval: 0.024 to 0.13%).
- For a *potential extension of the Order* through June 2007, the risk of premature mortality to a hypothetical maximally exposed individual would be 0.067% (confidence interval: 0.022% to 0.12%). If the Order were extended through December 2007, the hypothetical maximally exposed individual risk of premature mortality would be 0.13% (confidence interval: 0.045 to 0.24%).

There are important uncertainties that are relevant to both the maximally exposed individual and population analyses. First, there are uncertainties associated with the response factors as indicated by the 95% confidence intervals. (See text box.)

Another uncertainty is the health status of the affected persons. If the persons exposed to the highest concentrations are more healthy than average, the risks are lower. Conversely, if the people exposed to the highest concentrations are relatively unhealthy, the estimated premature fatality probability may be an underestimate. Further, there is uncertainty associated with the location of affected persons, e.g., people who may not be at home all day or workers who may be

outside much of the day, so their actual exposures may be lower or higher than assumed for this analysis. To reduce these uncertainties would require very detailed information about the health status and daily movements of a large number of people. Such detailed information is not available.

Another important uncertainty has to do with the air dispersion modeling. As discussed in Section 4.3.1, many assumptions and approximations were used in the air dispersion analysis. Where there was uncertainty, DOE selected assumptions that avoid underestimating the impacts of Plant operations. The net result of all these assumptions is most likely to overestimate maximum pollutant concentrations. In addition, Mirant has stated that the standard building dimensions used in AERMOD lead to overestimating the modeled downwash effect, with the result that modeled concentrations at Marina Towers are unrealistically high. EPA authorized Mirant to initiate the MES to help resolve this concern. Initial monitoring results for SO_2 monitors near the Plant tend to support Mirant's statement, but EPA has yet to reach a conclusion.

If the estimate of the downwash effect is too high, it would mean that the maximum exposures to stack emissions are overestimated and the risk to the hypothetical maximally exposed individual may be too high. However, overestimate of the risk to the hypothetical maximally exposed individual may not appreciably affect the risk to the population. The population health effect is the sum of the individual risks for the modeled population of 144,000 adults. Relatively few people live in the top floors of Marina Towers. Even if modeling with improved input parameters showed that pollutant concentrations at Marina Towers are lower than current estimates, the concentrations at points that are farther away and the exposures for most of the population would be little affected. Thus, the population risk is not expected to be much affected by more accurate modeled building dimensions.

EPA Scaling Technique. The EPA scaling technique is a simple method of making estimates of a variety of health effects. The health effects reported in Table 4.3.2-1 are those examined by EPA in its recent regulatory impact assessments for emission standards. The estimates of population health effects are higher than those that would result from the method above because the potentially affected population is much larger. The EPA scaling technique does not provide estimates of uncertainty or confidence intervals. However, the estimates of premature mortalities are based on Pope et al. (2002) cited above. Consequently, at least for the premature mortalities, it is reasonable to estimate that a 95% confidence interval would span at least 70% below to 80% above the expected incidences reported in Table 4.3.2-1 based on Pope's reported confidence intervals.

4.3.3 Water Quality

Two types of water quality impacts could result from Plant operations as a result of the Order. Plant operations could cause direct impacts to Potomac River water quality by changing the volume or characteristics of the effluent discharged from the Plant. Indirect impacts to regional water quality could result from changes in the emissions of air pollutants that are

Table 4.3.2-1. Expected incidence of short- and long-term health effects resulting from Mirant Plant operations for the population of the eastern United States

Health effect	Pre-shutdown (one year)	Pre-Order (285 days)	Order (285 days)	Order extension Oct. `06 – Jun. `07	Order extension Oct. `06 – Dec. `07
Premature mortality (adults, 30 and over)	37	5	14	12	23
Infant mortality (infants less than one year)	0.08	0.01	0.03	0.03	0.05
Chronic bronchitis (adults, 26 and over)	20	3	7	6	13
Non-fatal myocardial infarctions (adults, 18 and older)	50	7	18	16	31
Hospital admissions – Respiratory (adults, 20 and older)	13	2	5	4	8
Hospital admissions – Cardiovascular (adults, 20 and older)	11	2	4	3	7
Emergency room visits for asthma (18 and younger)	30	4	11	9	19
Acute bronchitis (children, 8-12)	46	7	17	14	29
Asthma exacerbations (asthmatic children, 6-18)	698	101	258	218	440
Lower respiratory symptoms (children, 7-14)	553	80	205	173	349
Upper respiratory symptoms (asthmatic children, 9-11)	423	61	157	132	267
Work loss days (adults, 18-65)	3,942	568	1,459	1,234	2,488
Minor restricted activity days (adults, age 18-65)	23,490	3,387	8,693	7,350	14,823

Source: DOE analysis of SO_2, NO_x, and $PM_{2.5}$ emissions from the Mirant Potomac River Generating Station, using EPA scaling technique (Personal communication between B. Hubbell, Health and Environmental Impacts Division, EPA, Research Triangle Park, North Carolina, and L.N. McCold, Oak Ridge National Laboratory, October 11, 2006).

subsequently deposited in surface waters or that are washed into surface waters after being deposited on the ground surface.

4.3.3.1 Direct impacts to the Potomac River

The operating changes associated with the pre-Order period or operations under the Order do not change the water quality characteristics of Plant intake water and effluents. Thus, the effect of the Plant on the pollutant load in the Potomac River (including suspended sediments, coliform bacteria, and metals) under different operating conditions can be assumed to be proportional to the volume of water used and discharged by the Plant. No chlorine was used in the Plant during pre-Order operations or under the Order; thus, Plant operations do not affect chlorine levels in the Potomac River.

Pre-shutdown operations. Under pre-shutdown operating conditions the Plant used Potomac River water and discharged effluents to the river as described in Section 2. The effects of many years of Plant operations are among the natural and human factors reflected in the existing water quality and ecological conditions in the river, as described in Sections 3.3.2.1 and

3.4.2.1. Table 2.4-1 presents data on the water quality of intake water and effluents associated with pre-shutdown operations.

Pre-Order operations. The Plant's water discharges to the Potomac River in December 2005 (assumed to be typical of pre-Order conditions) averaged 94 million gal/day (360,000 m^3/day), approximately 27% (on average) of the average pre-shutdown discharge volume (Section 2.4.2). Assuming that withdrawals from the river during any period are about 1% higher than monitored discharges (Section 2.3), withdrawals during this pre-Order period are estimated at less than 95 million gal/day (360,000 m^3/day). The reported maximum thermal discharge to the river in December 2005 was 969 Mbtu/hr. The much lower water and thermal discharge rates associated with pre-Order operations could contribute to improved river water quality relative to pre-shutdown operations, which could improve conditions for aquatic organisms (Section 4.3.4.2).

Operations under the Order and potential extensions of the Order. The Plant's water and thermal discharges to the river varied during the 285-day period of the Order. Operations during the line outage in January 2006 contributed to an average water discharge for the entire month of 266 million gal/day (1.0 million m^3/day), nearly three times the discharge recorded in the pre-Order period. Reported maximum thermal discharge to the river was 3,355 MBtu/hr, more than three times the December maximum. Operations in the period February through May 2006, a period of relatively low power demand (Figure 4.2-1) during which there were no line outages, resulted in an average discharge of 170 million gal/day (640,000 m^3/day), about 80% higher than pre-Order operations but only about half of the average for the pre-shutdown period. Maximum thermal discharges in this period ranged from 1,157 to 1,620 MBtu/hr. Average water discharge in June 2006 was 250 million gal/day (950,000 m^3/day). This value is 165% higher than discharge under pre-Order conditions, but is still 27% less than the average discharge under pre-shutdown operations before August 2005. Maximum thermal discharge in June 2006 was 2,406 MBtu/hr, which also is intermediate between pre-shutdown and pre-Order levels. The somewhat lower water and thermal discharge rates resulting from operations under the Order through June 2006 could contribute to improved river water quality relative to pre-shutdown operations, which could improve conditions for aquatic organisms (Section 4.3.4.2).

For operations under the Order following the commencement of daily predictive modeling in July 2006 (including the temporary extension of the Order to December 1, 2006, and any extension beyond that date), water and thermal discharges are assumed to be similar to those during pre-shutdown operations. Impacts are estimated to be the same as for pre-shutdown operations.

4.3.3.2 Indirect impacts to regional water quality

DOE identified and assessed two potential sources of indirect impact to regional water quality from deposition of Plant air pollutants: (1) nitrogen loading and (2) acid deposition.

Nitrogen loading. Deposition of nitrogen compounds emitted from the Plant contributes to nitrogen input to Chesapeake Bay and other waters in the region, thus contributing to the nutrient loading that degrades water quality (Section 3.3.2) and can impact aquatic organisms (Section 4.3.4).

Targets for reducing atmospheric nitrogen inputs have been set for the Chesapeake Bay as a whole (Section 3.3.2.5), but not for component watersheds. Therefore, DOE's assessment of the potential impacts of Plant operations on nitrogen loading to area surface waters focuses on Chesapeake Bay. Because nitrogen inputs due to pre-shutdown operations of the Plant are implicitly included in current Bay nutrient budgets, the reduced levels of operations associated with pre-Order conditions and the Order contribute toward the Chesapeake Bay Program's 8-million-lb (3.6-million-kg) target for reduction in atmospheric inputs of nitrogen (Section 3.3.2.5). In all cases the estimated reductions in nitrogen loading are small when compared with the total nitrogen input to the Bay.

Assumptions. DOE estimates (Section 4.3.1.5) that the Plant emitted 2,800 tons (2,500 metric tons) of NO_x per year under pre-shutdown operating conditions. In estimating the impacts of nitrogen emissions from the Plant on Chesapeake Bay water quality, DOE assumes that NO_x has the same nitrogen content as an equivalent mass of NO_2; the pre-shutdown NO_x emission is the equivalent of about 1.7 million lb/yr (770,000 kg/yr) of nitrogen.

To estimate the impact of the Plant on Chesapeake Bay nitrogen loading, DOE assumed that 10% of the nitrogen released from the Plant reaches the Bay, primarily due to being deposited directly on water or on impervious urban surfaces, while all other nitrogen emitted from the Plant is either consumed in terrestrial or aquatic ecosystems or deposited outside the Bay watershed (e.g., on the open Atlantic Ocean). (See Section 3.3.2.5.)

The above assumption is believed to be realistic, based on the following reasoning. Assuming that electric power plants such as the Plant are responsible for 38% of the atmospheric contribution of nitrogen to the Bay (consistent with their contribution to regional NO_x emissions, as discussed in Section 3.3.2.5), the total estimated electric-utility contribution to the Bay is about 35 million lb/yr (16 million kg/yr). The 170,000 lb/yr (77,000 kg/yr) of nitrogen estimated to reach the Bay as a result of Plant air emissions (10% of the total nitrogen emissions) are approximately 0.5% of this total electric-utility contribution. This 0.5% value is consistent with power-plant NO_x emissions inventories reported by EPA (2006b), which indicate that during several months in early 2005 the Plant accounted for about 0.5% of electric utility NO_x emissions in the seven-state region (i.e., Maryland, Virginia, Pennsylvania, New York, West Virginia, New Jersey, and Ohio) estimated to produce most of the air emissions that contribute nitrogen to the Bay.

Pre-shutdown operations. Based on the above assumptions and the Plant's estimated NO_x emissions under pre-shutdown operating conditions, pre-shutdown Plant operations contributed about 170,000 lb (77,000 kg) of nitrogen to the Bay annually, or about 0.2% of the total annual nitrogen input to the Bay that is attributed to atmospheric sources (Section 3.3.2.5).

Pre-Order operations. Based on the estimate of NO_x emissions presented in Section 4.3.1.5, pre-Order operations are estimated to emit nitrogen at an annual rate of about 470,000

lb/yr (220,000 kg/yr). For the 285-day duration of the Order (through October 1, 2006) operations at pre-Order levels would emit about 370,000 lb (170,000 kg) of nitrogen.

Assuming that 10% of the nitrogen from the Plant reaches the Bay, pre-Order operations, if extended for a full year, would contribute about 47,000 lb (22,000 kg) of nitrogen to the Bay annually. Compared with pre-shutdown operations, pre-Order operations would avoid an estimated 123,000 lb (55,000 kg) of annual nitrogen delivery to the Bay, thus potentially achieving about 1.5% of the Chesapeake Bay Program's targeted 8-million-lb (3.6-million-kg) reduction in atmospheric nitrogen input.

Operations under the Order. Based on the estimate of NO_x emissions presented in Section 4.3.1.5, operations under the Order emit nitrogen at a rate of about 1.5 million lb/yr (670,000 kg/yr). For the 285-day duration of the Order (through October 1, 2006) operations under the Order emit 1.2 million lb (530,000 kg) of nitrogen, delivering nitrogen to the Bay at an estimated rate of 150,000 lb (67,000 kg) per year. If sustained for a full year this level of operations would avoid about 20,000 lb (10,000 kg) of pre-shutdown nitrogen delivery to the Bay annually and would achieve about 0.2% of the Chesapeake Bay Program's goal for annual atmospheric nitrogen reductions.

Potential extension of the Order. DOE's analysis assumes that Plant operations after October 1, 2006, including operations during the temporary extension of the Order through December 1, 2006, and any subsequent extension of the Order, would utilize coal and emit NO_x at approximately the same rate as pre-shutdown operations, so there would be no reduction from pre-shutdown nitrogen delivery to the Bay and no contribution toward meeting the Chesapeake Bay Program's nitrogen-reduction goals.

Acid deposition. The Plant's air emissions of SO_2 and NO_x (Section 4.3.1) contribute to regional acid deposition. However, under all operating conditions acid-deposition impacts to water quality of streams in nearby watersheds, including the Anacostia, Patuxent, and nearby portions of the Potomac watershed, would be negligible because these watersheds are well buffered against acid rain (Section 3.3.2.6).

Pre-Order operations. Air emissions of SO_2 and NO_x under pre-Order conditions were about 28% of pre-shutdown emissions of these pollutants, proportionately reducing the Plant's contribution to regional acid deposition, relative to pre-shutdown operations.

Operations under the Order. Compared to pre-Order operations, operations under the Order increase the Plant's contribution to regional emissions of these air pollutants that produce acid deposition, but the Plant's contribution is smaller than under pre-shutdown operations. Over the 285-day duration of the Order, the Plant produced about 87% of the NO_x emissions that would have occurred for the same duration of pre-shutdown operations, but roughly three times the emissions estimated for pre-Order operations. SO_2 emissions also increased relative to pre-Order operations, but the use of trona caused emission of less than 45% of the SO_2 that would have been emitted from pre-shutdown operations.

Potential extension of the Order. Operations under the Order after October 1, 2006, including during the temporary extension of the Order to December 1, 2006, and any extension

beyond that date, are conservatively estimated to emit NO_x at the same annual rate as pre-shutdown operations, but use of trona is assumed to reduce SO_2 emissions by 50% compared with pre-shutdown operations. Thus, the Plant's overall contribution to regional acid deposition is smaller than under pre-shutdown operations.

4.3.4 Ecological Resources

Operation of coal-fired power plants can impact ecological resources through air, water, or solid waste releases that can result in acid deposition, nutrient enrichment (see section 4.3.3.2), or changes in water quality or quantity of the receiving bodies (Dvorak et al. 1978, EPA 2006c).

4.3.4.1 Acid deposition

Acid deposition can affect plant and animal species, both directly and indirectly (Schreiber 1995, Roth et al. 2005, EPA 2006a), but Plant emissions (discussed in Sections 3.3.2.6 and 4.3.3.2) are expected to have minimal impacts as described below.

Aquatic impacts. The ecological effects of acid rain are most clearly seen in aquatic environments (e.g., streams, lakes, marshes) located in watersheds where the soils have a limited buffering capacity (EPA 2006a). (See Section 3.3.2.6.) In areas where buffering capacity is low, acid rain can release aluminum, which is highly toxic to many species of aquatic organisms, from soil into lakes and streams. In general, lowering the pH of a water body can impair the ability of certain fish and other aquatic organisms to grow, reproduce, and survive.

Soils in the river and stream basins in the region where air emissions from the Plant are most likely to fall (e.g., Potomac, Anacostia, and Patuxent rivers; Rock Creek) are generally well buffered (CBWP-MANTA 2001, Roth et al. 2005, Shanks 2005; also see Sections 3.3.2.6 and 4.3.3.2). Mobilization of aluminum is, thus, unlikely to occur, and acid deposition will not greatly change the pH level of the streams. Therefore, acid deposition resulting from the DOE Order, including the temporary extension of the Order to December 1, 2006, and any extension beyond that date, would have minimal impacts on biological resources in regional waterways.

Terrestrial impacts. Increases in soil acidity can impair the ability of some species of trees to grow and resist disease, while dry deposition of acidic gases and particles can directly impact some terrestrial vegetation.

The effects of over 50 years of Plant operations are among the natural and human factors reflected in the existing ecological conditions near the Plant, as described in Section 3.4.1. Vegetation still actively grows nearby on Daingerfield Island and in the small wooded area next to the Plant (Figure 2-2). While the Order results in higher emissions of the air pollutants responsible for acid deposition than occurred during the pre-Order period (Sections 4.3.1 and 4.3.3.2), combined total estimates of emissions of these pollutants under the Order and any

extension of the Order, including the temporary extension, are still lower than during pre-shutdown operations, when vegetation was growing well near the Plant. Thus, the Order is unlikely to have negative impacts from acid deposition on vegetation or the wildlife that depends on it.

4.3.4.2 Impact of water quality changes

Nutrients. One of the main causes of aquatic habitat loss in the Chesapeake Bay watershed as a whole (CBP undated) is elevated loading of two nutrients: nitrogen and phosphorus. (See Section 3.3.) To the extent that the DOE Order changes loading of these two nutrients to surface waters compared to the pre-Order or pre-shutdown operating periods, there could be effects on habitats in the river for fish and submerged aquatic vegetation (Section 3.4.2.6), but the Plant's impact on nutrient loading would be small relative to the total.

As discussed in Section 4.3.3.2, nitrogen compounds are emitted from the Plant and augment the nitrogen input to Chesapeake Bay and other waters in the region, thus, contributing to the nutrient loading that impacts aquatic organisms and their habitat. During the first six months of operations under the DOE Order, the Plant's contribution to the nitrogen in the Bay increased over the pre-Order value, but was still lower than under pre-shutdown operating conditions. Operations under daily predictive modeling are estimated to contribute a similar amount of nitrogen as pre-shutdown operations. In all cases changes in the Plant's contribution of atmospheric nitrogen to the Bay are small (as discussed in Section 4.3.3.2), when compared with the total nitrogen input to the Bay.

Reported phosphorus levels in Plant water effluent (Table 2.4-1) were lower than those in the intake water, suggesting that Plant water use may reduce the phosphorus load and, thus, benefit aquatic systems. If the Plant reduces phosphorus concentration in effluent by 0.016 mg/L (Table 2.4-1), effluent discharge at the pre-shutdown rate of almost 345 million gal/day (1.3 million m^3/day) would remove about 48 kg/day of phosphorus. Reduced operating levels during pre-Order operations and the first six months of the DOE Order would have diminished the Plant's beneficial impact by removing proportionately less phosphorus than pre-shutdown operations or operations under daily predictive modeling. At any level of operations, however, any beneficial impact on phosphorus load resulting from Plant operations is small relative to the total daily input (from all sources) of phosphorus to the Potomac River, which has been estimated to be about 8,000 kg/day (Boynton and Swaney 1998), or the contribution of the nearby Blue Plains Wastewater Treatment Plant, which delivers 720 kg/day of phosphorus to the river when operating at its rated capacity of 370 million gal/day (1.4 million m^3/day) and discharging effluent with the phosphorus concentration of 0.18 mg/L allowed by its NPDES permit (Table 3.3-1).

Other contaminants. As discussed in Section 4.3.3.1, changes under the Order in the amount of water used and discharged by the Plant could cause proportional, but small, changes

in concentrations of other pollutants removed from or returned to the Potomac River that are unlikely to result in impacts to organisms or their habitats in the Potomac River.

Trona use. Use of trona may change the landfill effluent discharged to Mataponi Creek by increasing pH and concentrations of sodium sulfate, sodium chloride, selenium, arsenic, and dissolved metals. (See Section 4.3.5.) Modest increases in pH that result from carbonate leaching could be beneficial to aquatic life in the creek due to buffering of acidity. Sulfate compounds are neither toxins nor nutrients; thus, increased concentrations of sodium sulfate would not be expected to impact the creek's aquatic life. Any increase in sodium chloride would likely be indistinguishable from background.

Release of arsenic and selenium could, however, have adverse impacts on aquatic biota and other wildlife that consume these organisms, depending upon the levels at which they occur in the effluent. As noted in Section 4.3.5, monitoring of collected landfill leachate and stormwater, as required under the existing discharge permit, should identify the potential for any problems from selenium before discharges occur. Arsenic levels are not, however, currently monitored prior to water discharge, so there is a potential for arsenic to be released to the creek at concentrations that could be harmful to aquatic life.

Selenium can enter the food web from both sediments and surface water (EPA 2006e). In the food web it undergoes bioconcentration, bioaccumulation, and biomagnification as organisms that first take it in are eaten by others. Elevated levels cause growth reduction in green algae. In other aquatic organisms a number of adverse effects have been observed including loss of equilibrium and other neurological disorders, liver damage, reproductive failure, reduced growth, reduced movement rate, chromosomal aberrations, reduced hemoglobin and increased white blood cell count, and necrosis of the ovaries.

Arsenic can cause cancer and genetic mutations in aquatic organisms, with those effects including behavioral impairments, growth reduction, appetite loss, and metabolic failure (EPA 2006e). Aquatic bottom feeders are more susceptible to arsenic than other organisms.

4.3.4.3 Impacts of changes in water use

Once-through cooling water systems such as used by the Plant can impact aquatic species by impingement (when aquatic organisms become trapped on the intake screens), entrainment (when aquatic organisms are taken in and pass through the cooling water intake system), or thermal changes (Jensen 1981). Impingement and entrainment are often roughly proportional to the volume of water withdrawn, as well as the numbers and species of aquatic organisms in the water body. At the Plant the numbers and species of fish, crabs, and other aquatic organisms that are susceptible to impingement or entrainment at any one time depends on the season of the year, annual fluctuations in relative abundance, and the impact of restoration activities in the Chesapeake Bay watershed. Overall, the effect on species or their habitats of water use and changes in water use by the Plant in different operation modes is expected to be small. The

Plant's thermal discharge is permitted and has been shown to not form a barrier to movement or cause lethality of aquatic organisms.

Impingement. Mirant studied impingement at the Plant during 1981-1982 and 2003-2004 (Pepco 1982; Personal communications between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, July 24, and August 18, 2006). Rates of cooling water withdrawal at the Plant were similar for both study periods (i.e., pre-shutdown conditions). For 1981-1982 the estimated impingement was 206,379 finfish[31] and 56,600 blue crabs; for 2003-2004 the annual estimates were 19,392 finfish and no blue crabs. In the 1981-1982 study over 90% of the fish were impinged in the winter and spring. The main fish species impinged in both studies were species that were either not used commercially (e.g, gizzard shad) or were too small to be of commercial value (e.g, white perch). Some fish exhibited disease conditions or appeared stunted, indicating that they were in poor health.

Although the 2003-2004 study is likely more representative of the fish community that is currently susceptible to impingement by the Plant, the large differences in the results of the two studies illustrate the potential magnitude of annual variation in potential impacts, so results of both studies were used as a basis for assessing impacts of the Order.

Impingement is assumed to be proportional to water intake for the Plant. At pre-Order operating levels the Plant withdraws about 27% of the amount of water it used during the pre-shutdown period. (See Section 4.3.3.1.) Thus, impingement under pre-Order conditions is estimated to amount to about 5,200–55,000 fish per year, based on the levels observed during the two studies at the Plant.

Under the Order before the commencement of daily predictive modeling (i.e., between January and June 2006), monthly Plant water use ranged from 42 to 77% of monthly use in the pre-shutdown period, averaging about twice the use during the pre-Order period. Assuming that 90% of annual impingement occurs during the winter and spring months of January through June, impingement during this time period is estimated at approximately 9,400–99,000 fish. At the high end of the range the number of fish impinged under the Order on an annual basis is equivalent to about 3% of the estimated 4.9 million fish in the Potomac-Washington Metro Basin (Maryland DNR undated-b).

Following the commencement of daily predictive modeling in July 2006, the Plant is assumed to withdraw water at pre-shutdown levels, resulting in annual impingement rates within the range indicated by the two studies (i.e., about 19,000–206,000 fish per year). However, because the 1981-1982 study indicated that less than 10% of annual impingement occurs during the summer months, operations under the Order during the period July through September 2006 are estimated to have impinged fewer than 1,900–21,000 fish. The temporary extension of the Order to December 1, 2006, and any extension beyond that date would result in cooling water

[31] The number of fish impinged is for the 56-week duration of the study. Thus, the annual rates would be slightly less.

withdrawal rates and annual impingement rates similar to pre-shutdown conditions (i.e., about 19,000–206,000 fish per year).

Not all impinged fish are killed; new intake screens, particularly the one with the fish buckets (Section 2.2), should lower impingement mortality. Fish or other organisms impinged on the water intake screens are washed off the screens and returned to the river on the south side of the cove area next to the Plant, south of the water intake area. (See Figure 2.1-1.)

Little impact is expected to the blue crab population as studies have indicated that initial and latent mortality from impingement is less than 10% (Pepco 1982). Also, blue crabs are found near the Plant only in years when the river is particularly salty (Personal communication between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, August 17, 2006). A difference in the salt level in the river between the two impingement studies is the likely explanation for the difference in the observed number of impinged crabs.

Entrainment. Mirant studied entrainment of fish eggs and larvae at the Plant in 1981 and 2005. Preliminary results from the 2005 study are similar to those from the 1981 study reported below (Pepco 1983; Personal communication between A. Wearmouth, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, August 25, 2006).

Only organisms small enough to pass through the screens on the water intakes are drawn into the Plant where they are subjected to heat, fluid, and mechanical stresses (Cada et al. 1981). Entrainment of fish eggs and larvae is mainly an issue in the period during and soon after fish spawning, from early spring through mid-summer.

During the 1981 study, eggs and larvae of anadromous species (i.e., white perch and herring) were 99% of the total number entrained. Freshwater species (e.g., minnows [fish in the Cyprinidae family], tessellated darter [*Etheostoma olmstedi*]) were entrained in very low numbers, less than 1% of the total.

The major spawning area for both white perch and herring is about 9 miles (14 km) above the Plant at Little Falls. As they mature, the larvae float downriver, past the Plant, mostly in a dredged channel well offshore. The Plant draws cooling water primarily from shallow water near shore, which results in relatively low entrainment rates. Significant spawning of white perch and herrings also occurs in other portions of the Potomac River and its tributaries. Thus, while some fish spawn in the Washington, D.C. portion of the Potomac River, spawning there represents a small portion of the spawning of the Potomac River population. The best estimate of the percent entrainment varied from 1.6% for white perch yolk-sac larvae (an early larval stage) to 8.7% for herring larvae after yolk absorption (Pepco 1983).

Pre-Order operations. There would have been no entrainment of fish eggs and larvae during pre-Order conditions in December 2005 because of the absence of these organisms from the Potomac River at that time. On an annual basis, assuming that entrainment is proportional to water intake, pre-Order conditions would result in entrainment at about 27% of pre-shutdown rates.

Operations under the Order. Under the Order before the commencement of daily predictive modeling (i.e., during January through June 2006) entrainment is estimated to have

occurred at approximately twice the calculated pre-Order rates, but substantially less than pre-shutdown levels (about 55% of pre-shutdown rates). Following commencement of daily predictive modeling in July 2006, entrainment is estimated to have been similar to pre-shutdown conditions for the summer season (owing to similar cooling water withdrawal rates). The temporary extension of the Order to December 1, 2006, and any extension beyond that date would be expected to result in entrainment rates similar to those that occurred during the pre-shutdown time period.

Since entrainment was not a major issue when the Plant was operating at the pre-shutdown level before August 2005, entrainment resulting from operations under the Order or any extension of the Order would not have a major impact on fish populations.

Temperature changes. The Plant's NPDES permit (Section 2.4.2) limits temperature rise in the Potomac River from water discharge to 2.8°C above ambient temperature beyond a 1,000-ft (300-m) radius in order to prevent formation of a barrier to movement of aquatic life or lethality to passing organisms. Based on a 2001 study (Mirant 2002), the thermal plume from the Plant does not form a barrier to movements of aquatic life or cause lethality to passing organisms. The main path for movement of aquatic organisms is the river channel, which is unaffected by the warm water plume from the Plant (Mirant 2002). Thus, no blockage to aquatic life movement is expected from the thermal plume under any assessed operating conditions.

If pre-Order operating conditions continued throughout the year, slightly lower summer water temperatures would result. This could slightly reduce the potential for nuisance algal blooms (Section 3.4.2). Similar, but smaller, benefits could be expected in 2006 because Plant operations under the Order before the commencement of daily predictive modeling resulted in thermal input levels intermediate between pre-Order and pre-shutdown operations (Section 4.3.3.1). Following commencement of daily predictive modeling in July 2006 and throughout any extensions of the Order, however, thermal input to the river is assumed to be similar to pre-shutdown conditions.

If there were a sudden shutdown of the Plant during the winter under any operating conditions, fish that were acclimated to the warm discharge might suffer cold shock when they lose the warm water habitat.

4.3.4.4 Special status species

The NPDES permit stated that the Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS), the agencies responsible for implementing the Federal Endangered Species Act (ESA), had indicated that the Plant's wastewater discharges were not adversely affecting the three Federally listed species mentioned in the permit. (See Section 3.4.2.)

During consultation with Mirant before the start of sampling for an entrainment study, FWS concluded that taking of eggs of the shortnose sturgeon, an endangered species, in the sampling process was not an issue as there was no possibility of finding them (Personal

communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006).

While bald eagles are occasionally seen near the Plant, the site provides no suitable nesting habitat for them (Personal communications between A. Wearmouth and D. Knight, Mirant Corporation, and M.S. Salk, Oak Ridge National Laboratory, July 24, and 25, 2006, respectively).

The Plant site does not provide any suitable habitat for any of the other special status species (i.e., the Hay's Spring amphipod, the Federal species of concern, and the Virginia state-listed species) discussed in Section 3.4.2. There have been no reported adverse impacts to any of these species due to the Plant while operating at the pre-shutdown level before August 24, 2005. Since Plant operating levels under the DOE Order are no higher than they were under pre-shutdown conditions, adverse impacts to any of the special status species would not be expected.

In order to comply with Section 7 of the ESA, DOE sent letters to FWS and NMFS as part of informal consultation. (See Chapter 6 and Appendix D.) The NMFS by letter dated October 3, 2006, concurred with DOE's determination that continued operation of the Plant under the Orders is not likely to adversely affect any listed species. The FWS by letter dated November 20, 2006, stated that only occasional transient individuals of Federally listed endangered or threatened species are known to exist within the project impact area. Both agencies concluded that no further consultation under Section 7 of the ESA is required.

4.3.5 Waste Management

Potential waste management impacts from the Order include (1) impacts to landfill capacity resulting from changes in the quantity of waste generated and (2) changes in environmental impacts of waste management resulting from changes in solid waste characteristics. Impacts related to solid waste transportation are discussed in Section 4.3.6.

4.3.5.1 Impacts on landfill capacity

Assumptions. In estimating the impacts of operations under the Order on remaining waste capacity in the Mirant Brandywine ash landfill used for disposal of fly ash from the Plant (Section 3.5), DOE made the following assumptions, derived from GB&B Inc. (2005):

- remaining disposal capacity at the beginning of 2005 was 2.07 million yd^3 (1.58 million m^3);
- ash placed in the landfill has an in-place density of 1.1 ton per yd^3 (760 kg per m^3); and
- throughout the period of analysis the Chalk Point Generating Plant would generate 206,000 tons (187,000 metric tons) of ash per year, of which 15% would be recycled and 85% would be placed in the Brandywine landfill.

Data and assumptions for pre-shutdown operations. Mirant's records indicate that the Plant sent 113,865 tons (103,297 metric tons) of ash to the landfill during the period January

through August 2005, prior to the events and actions addressed in this SEA (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). This corresponds to an annual ash generation rate of 170,000 tons (150,000 metric tons) per year, which is somewhat higher than the rate (136,000 tons [124,000 metric tons] per year) used in the GB&B Inc. (2005) analysis.

Assumptions for pre-Order operations. Making the conservative assumption that, on average, pre-Order operations of the Plant during the last three months of 2005 generated fly ash at 20% of the rate recorded for the first eight months of the year, DOE estimated that under pre-Order operating conditions the plant would generate fly ash at a rate of 34,000 tons (31,000 metric tons) per year. (To simplify the assessment of waste management impacts, DOE assumed that under pre-Order operating conditions trona use did not affect the rate of ash generation. This assumption is conservative, in that it minimizes the estimated impacts of pre-Order operations, thus increasing the contrast between the impacts of pre-Order operations and operations under the Order.)

Data and assumptions for operations under the Order. Mirant's records indicate that the Plant sent 28,399 tons (25,763 metric tons) of ash to the Brandywine landfill during the 3-month period March through May 2006 (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). In estimating the impacts of operations under the Order on landfill capacity, DOE assumed that fly ash was generated at the same average rate from February 2006 until the beginning of June, when the Plant began operating under the ACO. From that time forward the analysis conservatively assumes that under the Order the Plant operates, on average, at pre-shutdown levels, including the temporary extension of the Order to December 1, 2006, and any extension beyond that date.

Impacts. Using the data and assumptions summarized above, DOE estimated total Brandywine landfill waste disposal (from both power plants) during 2005 (prior to the Order) at 269,000 yd^3 (206,000 m^3), which is somewhat less than the historical annual disposal rate of 278,000 yd^3 (213,000 m^3) used in the GB&B Inc. (2005) analysis. This value then became the starting point for analysis of the effect of several different Plant operating modes on the remaining capacity and operating life of the landfill, summarized in Table 4.3.5-1.

Pre-shutdown operations. The 2005 analysis by GB&B Inc. projected that with continued operations at then-current (i.e., pre-shutdown) operating levels, the Brandywine ash landfill would be able to continue receiving ash from the Plant and Mirant's Chalk Point Generating Plant until the middle of 2012.

Pre-Order operations. Table 4.3.5-1 indicates that under pre-Order operating conditions, beginning with the date of the Order and continuing indefinitely, the landfill would be able to receive waste from both power plants for approximately the next 9 years, through the middle of 2015.

Operations under the Order and any extension. To indicate the potential range of impacts from operations under the Order and any extension (including the temporary extension through December 1, 2006), Table 4.3.5-1 presents estimates of disposed waste volume and remaining

Table 4.3.5-1. Impact of Plant operations on remaining operating life of the Brandywine ash landfill

Plant operating mode [a]	Disposal rate for Plant fly ash (yd^3/year) [b]	Estimated full-capacity date for landfill
Pre-shutdown operations [c]	119,000	mid-2012
Plant operates at pre-Order level [d]	31,000	mid-2015
Plant operates in accordance with the Order, without trona injection [e]	varies [e]	late 2011
Plant operates in accordance with the Order (as above), with trona injection [f]	310,000 [f]	early 2010

[a] Mirant's Chalk Point Generating Plant is assumed to operate under all scenarios, generating 159,000 yd^3 of in-place waste annually. If Chalk Point Generating Plant operated and the Mirant Potomac Plant did not, the estimated full-capacity date for the landfill would be the end of 2017 (GB&B 2005).
[b] To obtain the approximate equivalent numerical value in tons/year, multiply by 1.1.
[c] These values are from GB&B Inc. (2005).
[d] Pre-Order level of operations is conservatively estimated to be equivalent to approximately 20% of pre-shutdown operations.
[e] Due to line outage conditions in January 2006, operations in accordance with the Order during that month are assumed to have resulted in waste disposal at the pre-shutdown rate. Operations during February through May are assumed to have resulted in waste disposal at the annual rate of 103,000 yd^3/year recorded during March through May (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006). Beginning in June 2006, the Plant is assumed to operate at the pre-August 2005 level, without trona injection, resulting in waste disposal at annual rate of 155,000 yd^3/year.
[f] Beginning in June 2006, trona injection is assumed to double the quantity of waste requiring disposal.

landfill life for two different assumptions: (1) the Plant operates at pre-shutdown levels, but with no use of trona, after the beginning of June 2006 (since trona is used in operations under the Order, this assumption results in a lower-bound estimate of potential impacts from the Order) and (2) the Plant operates at pre-shutdown levels beginning in June 2006 and trona is injected at a rate which doubles the pre-shutdown rate of solids generation. Trona injection in the Plant can substantially increase ash production; at injection rates necessary to achieve maximum SO_2 removal, trona injection could double or triple the quantity of fly ash waste generated by the Plant (Mirant 2006c). Because trona injection is done only part of the time that the Plant operates and Mirant records of fly ash generation during the period March through May 2006 (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006) indicate that trona use during that period increased fly ash production by approximately 50% over the quantity expected based on coal utilization during the same period, the assumption that trona use doubles the rate of fly ash generation is expected to provide an upper bound on the potential impacts of trona use on landfill capacity. DOE's estimates of the potential impact of the Order on landfill operating life (Table 4.3.5-1) assume that operations

continue indefinitely at pre-shutdown levels, instead of ending when the Order or any extension to the Order expires.

The table indicates that with the level of Plant operations estimated under the Order, but without trona use after June 2006, the landfill's operating life would be about one-half year shorter than projected by GB&B (2005) for pre-shutdown conditions, but about 3.5 years shorter than under pre-Order operations. (Note that this analysis assumes that the ash-generation rate reported in the first 8 months of 2005 would continue, rather than the lower rate assumed by GB&B.) Use of trona would cut almost two additional years off the Brandywine landfill's life expectancy, causing it to reach capacity in a little more than three years.

The assumptions of this analysis are conservative, but the limited landfill life that is estimated to remain if trona injection continues at a high rate may not provide sufficient lead time for siting a new ash landfill. If the Brandywine landfill were to reach capacity before a new ash landfill were sited, Mirant could ship fly ash to a commercial sanitary landfill until a new landfill became available.

Because commercial landfill capacity in the region is very limited (Metropolitan Washington Council of Governments 2001, VDEQ 2002, Harrison 2004, MDOE 2005), ash might need to be transported long distances if it is required to be sent to a commercial landfill licensed for municipal solid waste. Several large privately owned Virginia landfills receive municipal solid waste from outside the local area (Metropolitan Washington Council of Governments 2001). The nearest of these landfills is in King George County, about 60 miles (100 km) by road from the Plant; others are in the Richmond area, more than 100 miles (160 km) from the Plant. If the state regulatory agency allows coal combustion ash disposal in landfills permitted for disposal of construction and demolition debris (in Maryland, these are called "rubble landfills" or "rubblefills"), there are private landfills closer to the Plant (in Lorton, Virginia, and in Prince George's and Baltimore counties in Maryland) that possibly could be used. It has been estimated that the Lorton landfill will reach capacity before 2011 (Harrison 2004), but the state of Maryland has received applications to site several additional commercial rubble landfills (MDOE 2005), giving some assurance that the region will continue to have disposal capacity for construction and demolition waste.

4.3.5.2 Effects of trona use on the environmental consequences of waste management

In addition to increasing the volume of solid waste requiring management, operation of the Plant with trona injection alters the chemistry and physical properties of the fly ash waste, potentially changing the environmental consequences of its management. (Quantities and characteristics of the Plant's bottom ash are not affected by the use of trona.)

Chemical characteristics of Plant fly ash. Reaction of trona (sodium sesquicarbonate; $Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$) with SO_2 in the exhaust gas results in the formation of solid sodium sulfate compounds (assumed to be Na_2SO_4), along with the release of gaseous CO_2. The resulting

sodium sulfate is incorporated into the fly ash captured in the Plant's precipitators, together with mineral ash derived from coal combustion and unreacted trona (which is assumed to be dehydrated in the exhaust gas stream, forming sodium carbonate). Because the trona feed rate is typically several times larger than the feed rate calculated to be necessary to react chemically with SO_2 in the air emissions, the fly ash captured in the precipitators contains several times more sodium carbonate than trona reaction products. Although trona use enhances particulate capture in precipitators (Mirant 2006c), thus adding to the volume of fly ash, the increase in Plant fly ash volume that results from trona injection is due almost entirely to incorporation of trona residue into the fly ash. The trona-ash waste stream also can be assumed to include minor amounts of (1) any trace elements found in the raw trona and (2) compounds formed when other gases in Plant emissions react with trona.

Table 4.3.5-2 presents results of chemical analyses of four samples of ash produced in October and November 2005, including two samples produced during Plant operations without trona injection and two samples produced during trona injection. Comparison of the two pairs of analyses illustrates that trona use converts the Plant's fly ash from a largely insoluble mineral ash (oxide percentages of silica and alumina total 84-86% in the pair of samples produced during operations without trona injection) into a mixture of mineral ash and water-soluble carbonates and salts (the high values for sodium and alkalinity in the second pair of samples in Table 4.3.5-2 identify the sodium carbonate component of the ashes produced during trona injection). Trona use increases ash pH (which already is high, indicating an alkaline material) but also greatly increases alkalinity, which is a quantitative measure of the amount of material available to react with acid. Sulfate, which is a very minor component of ash produced without trona injection (first pair of analyses), is a significant fraction of the ash produced with trona (second pair of analyses). With trona use measurements of loss on ignition (a test used to indicate the level of unburned carbon in a sample) increased from 5% and 12% to values of 20% and higher. Trona addition should not affect the amount of unburned carbon in fly ash, so the increased measured values of loss on ignition probably are attributable to volatilization of trona-related constituents. Chloride was not measured, but it is likely that some sodium chloride is included in the ash due to chemical reaction of trona with the small amounts of chlorine present in Plant emissions.

Selenium concentrations are increased approximately 10-fold in the ash produced when trona is used (second pair of selenium in Table 4.3.5-2) compared with ash produced by Plant operations without trona use (first pair of selenium results in Table 4.3.5-2). The source of the increased selenium in the trona ash has not been determined, but it is likely that selenium (a trace constituent in coal that can volatilize during coal combustion) in Plant exhaust gas reacts with sodium carbonate or trona and is incorporated into the fly ash as solid sodium selenate, Na_2SeO_3. This chemical reaction is used industrially when sodium carbonate (often referred to as "soda ash") is used in the commercial production of selenium metal to isolate selenium from various other compounds and convert it to the sodium selenate form (WebElements 2006). Although selenium might also be present as an impurity in the natural trona used in the Plant, it is not mentioned in published reports about this material (Dyni 1991, 1996).

Table 4.3.5-2. Concentrations of major constituents and trace elements in samples of Plant fly ash resulting from operations with and without trona injection.

Parameter (units)	Ashes produced without trona injection		Ashes produced during high-rate trona injection	
	Load following	Baseline	Low load	Full load
Silica (%)	56.4	59.3	33.2	38.6
Alumina (%)	27.4	26.6	15.4	17.5
Titania (%)	1.4	1.3	0.7	0.9
Iron (as % FeO)	5.6	5.3	3.1	3.4
Calcium (as % CaO)	1.4	1.3	0.8	1.1
Magnesium (as % MgO)	1.4	1.3	0.8	1.1
Potassium (as % KO)	3	2.5	1.3	1.7
Sodium (as % Na_2O)	0.34	0.32	39.2	28.3
Sulfate (as % SO_3)	0.22	0.17	3.4	5.7
pH (pH units)	10.2	10.2	11.1	11.0
Alkalinity (% $CaCO_3$ equivalent)	0.55	0.55	39.21	32.4
Lead (mg/kg)	15	15	8.7	10
Arsenic (mg/kg)	47	39	31	26
Barium (mg/kg)	680	660	310	360
Cadmium (mg/kg)	0.29	0.39	0.2	0.28
Chromium (mg/kg)	13	19	7.7	13
Selenium (mg/kg)	1.1	ND [a]	15	11

[a] ND = Not detectable

Source: Mirant (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006)

Measured concentrations of lead, arsenic, barium, and chromium are lower in ash produced during trona operations, probably indicating a dilution effect from the addition of trona components to the mineral ash. Cadmium concentrations are similar in both types of ash. Mercury and silver concentrations are not presented in Table 4.3.5-2 because these metals were below detection limits in all samples.

The ash samples were tested for leachability using the Toxicity Characteristic Leaching Procedure (TCLP) (Personal communication between A. Wearmouth, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 21, 2006). The TCLP simulates leaching in the acidic environment of a municipal solid waste landfill and is one of the tests specified under the Resource Conservation and Recovery Act (RCRA) for determining whether a solid waste is a hazardous waste. TCLP extracts were analyzed for lead, silver, arsenic, barium, cadmium,

chromium, selenium, and mercury. These test results do not affect the regulatory status of Plant ash because ash from the combustion of coal, including flue gas emission control waste (such as the trona component of Plant fly ash), is exempt from RCRA regulation as a hazardous waste (40 CFR 261.4).

Barium was the only metal detected in TCLP leachates from the two ash samples produced without trona injection, with concentrations of 0.28 and 0.43 mg/L. Leachates from the two ash samples obtained during trona use had somewhat higher concentrations of barium (0.63 and 0.93 mg/L), but all barium concentrations were below the primary drinking water standard of 1 mg/L, as well as the 100 mg/L threshold for identifying a waste material as a RCRA hazardous waste.

TCLP leachates from both of the ash samples produced during trona injection also contained detectable levels of arsenic and selenium. The measured arsenic concentrations of 1.4 and 1.1 mg/L exceed the primary drinking water standard of 0.05 mg/L, but not the 5 mg/L threshold for identifying a waste material as a hazardous waste. Measured selenium concentrations of 1.1 and 0.77 mg/L also exceed the primary drinking water standard, which is 0.01 mg/L, and the higher measurement exceeds the 1 mg/L threshold for identifying a waste material as a hazardous waste. (As discussed above, however, Plant ash is exempt from RCRA regulation as a hazardous waste.) Sodium selenate (the form in which selenium is likely to be present) is soluble in water, and the presence of sulfate is likely to increase the solubility of both arsenic and selenium.

Implications for waste management operations. Although ash produced during trona injection has reduced pozzolanic activity (Section 2.4.3), it still has significant pozzolanic properties that facilitate its management. Mirant personnel report that trona use does not adversely affect ash workability or its physical stability after placement in the Brandywine ash landfill (Personal communication between D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 12, 2006). Thus, there should be no adverse consequences for the emission of windblown dust or for successful stabilization and closure of completed portions of the landfill. Ash produced during trona injection has, however, been observed to be more corrosive than other ash wastes handled at the Brandywine ash landfill (presumably due to the sulfate component), increasing the need for equipment maintenance and possibly accelerating the need for equipment replacement (Personal communication between A. Wearmouth and D. Cramer, Mirant Corporation, and E.D. Smith, Oak Ridge National Laboratory, July 14, 2006).

Fly ash generated during trona use has pozzolanic activity that is too low for most structural uses (TFHRC undated) and contains substantial amounts of sulfate and other soluble constituents that would reduce its suitability for construction use. Therefore, it is unlikely that any Plant fly ash generated during trona use can be beneficially used as a construction material. However, Mirant might be able to find other beneficial uses for this material. For example, due to its high alkalinity, the ash generated during trona production might be a suitable fill material in settings where alkaline material is needed to neutralize acids, such as in waste-site restoration or coal mine reclamation.

Implications for impacts of the Brandywine ash landfill. Leaching of the fly ash produced during trona injection would increase the release of dissolved solids into the landfill leachate that eventually is discharged to Mataponi Creek.

Sodium sulfate, sodium carbonate, and sodium chloride, which are major chemical constituents of the ash produced during trona injection (see discussion above), are all soluble and could be readily released into the leachate. Leachate pH is likely to be higher due to the presence of large amounts of carbonate.

The TCLP test results indicate a potential for the waste produced during trona injection to release the trace constituents selenium and arsenic. The presence of soluble sulfate and carbonate in leachate might increase the solubility and mobility of these or other trace constituents in the fly ash. Because the TCLP test protocol uses acidic leaching conditions, the TCLP test results may not be good predictors of the potential for selenium and arsenic to leach in the alkaline conditions found in the fly ash landfill. Leach testing using "synthetic precipitation" or "synthetic groundwater" would be more reliable than the TCLP for predicting contaminant mobility in the environment of a fly ash landfill.

Modest increases in effluent pH could be beneficial due to buffering of acidity, but there is a possibility of generating a leachate with a pH higher than permitted for discharge. Release of arsenic and selenium to Mataponi Creek could result in adverse impacts to aquatic biota and other wildlife that consume these organisms (Section 4.3.4).

Increases in release of other dissolved solids are not expected to adversely affect creek water quality. Increased concentrations of sodium sulfate would not be expected to affect the creek's suitability for aquatic life, since sulfate compounds are neither toxins nor nutrients. Any increase in sodium chloride would likely be indistinguishable from background.

If landfill leachate or storm water had unacceptably high levels of pH, selenium, lead, iron, copper, or zinc, the monitoring required under the existing discharge permit for the landfill (Section 3.5) should identify the presence of these contaminants before the water was discharged, thus providing an opportunity to make arrangements to treat the water before discharges occur. Current discharge monitoring does not, however, provide for detection of arsenic, so surface water releases of arsenic could go undetected.

Similarly, the current groundwater monitoring program (Section 3.5) should provide for detection of unacceptably high levels of pH, chloride, sulfate, and several dissolved metals before any substantial migration occurred. However, groundwater is not monitored for either arsenic or selenium, so groundwater releases of these substances could go undetected. Because shallow groundwater in hydrologic settings similar to the landfill site flows primarily to nearby streams, any adverse impacts from undetected groundwater releases of selenium or arsenic would be experienced in Mataponi Creek and its tributaries.

4.3.6 Transportation Resources

The primary impacts to transportation associated with Plant operations are increases in rail and road traffic due to trains and trucks traveling to and from the Plant.

Impacts from traffic increases due to Plant operations are considered in the context of existing traffic conditions. Other ongoing and future actions in the area that generate traffic or affect the capacity of transportation facilities also contribute to cumulative transportation impacts, including increased traffic and noise. Actions that could combine with Plant operations to create cumulative impacts include the 13 background developments that have been identified (Baxter 2006) as increasing automobile and truck traffic in the vicinity of the Brandywine landfill facility and contributing to the exacerbation of existing road traffic problems, especially on Maryland Route 381. (See Section 3.6.2.) The Woodrow Wilson Bridge Project (Section 3.6.2) is the only highway construction and maintenance project in the Virginia or Maryland Department of Transportation databases (VDOT 2006, MDOT 2006) that is likely to contribute to the cumulative impacts of Plant operations. Truck traffic from the Plant that crosses the bridge going to and from the Brandywine facility would combine with the increased traffic, delays, and noise generated by the Woodrow Wilson Bridge Project to contribute to cumulative impacts on transportation.

The following sections discuss transportation impacts for each of the Plant operating scenarios.

4.3.6.1 Pre-shutdown operations

Rail. Under pre-shutdown operations the Plant used about 2,280 tons (2,052 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant required about 23 rail car loads of coal per day. This demand could be met with five coal deliveries to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, five 40-car trains per week did not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, pre-shutdown operations did not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stopped traffic on the Parkway for ten periods of about 2 minutes each week, while typical nighttime operations (40-car trains) stopped traffic on the Parkway for five periods of about 4 minutes each week (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Road. Under pre-shutdown operations the Plant generated about 470 tons (430 metric tons) of ash per day. Assuming the use of 24-ton (22-metric ton) dump trucks, ash removal required about 28 round trips each weekday from the Plant to the Brandywine facility. These trips had a minor impact in terms of traffic on the local streets used to access the Plant, as the streets have relatively little traffic and operate at a level-of-service at or near “A” (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the 28 truck trips attributable to pre-shutdown Plant operations were not a major part of the traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6-1). However,

pre-shutdown operations did contribute to the existing traffic problems on Maryland Route 381 (see Section 3.6.2).

4.3.6.2 Pre-Order operations

Rail. Under pre-Order operations the Plant used about 540 tons (490 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant required about 5.5 rail car loads of coal per day. This total demand could be met with one coal delivery to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, one 40-car train per week did not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, pre-Order operations did not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stopped traffic on the Parkway for two periods of about 2 minutes each week, while typical nighttime operations (40-car trains) stopped traffic on the Parkway for one period of about 4 minutes each week (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Road. Under pre-Order operations, the Plant is estimated to have generated about 95 tons (86 metric tons) of ash per day. Assuming the use of 24-ton (22-metric ton) dump trucks, ash removal required about five or six round trips each weekday from the Plant to the Brandywine facility. These trips had a negligible impact in terms of traffic on the local streets used to access the Plant, since the streets have relatively little traffic and operate at an level-of-service at or near "A" (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the addition of five or six truck trips to the existing traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6-1) represented only a small impact. However, pre-Order operations did contribute to a small extent to the existing traffic problems on Maryland Route 381. (See Section 3.6.2.)

4.3.6.3 Operations under the DOE Order, temporary extension, and potential additional extensions

Rail. Under the Order before the commencement of daily predictive modeling (between December 20, 2005, and June 30, 2006), the Plant is assumed to have used an average of about 1,990 tons (1810 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant required about 20 rail car loads of coal per day. In addition, the use of trona required delivery by two rail cars per day. This total demand (about 22 rail cars per day) could be met with four coal/trona deliveries to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, two 40-car trains per week did not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, operations between December 20, 2005, and June 30, 2006, did not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stopped traffic on the Parkway for eight periods of about 2 minutes each day, while typical nighttime operations (40-car trains) stopped traffic on the Parkway for four periods of about 4 minutes each night (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Following commencement of daily predictive modeling (on July 1, 2006), including the temporary extension of the Order to December 1, 2006, and any extension beyond that date, the Plant is assumed to operate at a level similar to pre-shutdown operations, but with the addition of trona. Thus, the Plant uses an average of about 2,280 tons (2,050 metric tons) of coal per day. Assuming the use of 100-ton (91-metric ton) rail cars, the Plant requires about 23 rail car loads of coal per day. In addition, the use of trona requires delivery by two rail cars per day. This total demand (about 25 rail cars per day) could be met with five coal/trona deliveries to the Plant each week using a 40-car train. Because the Plant has its own rail spur and train yard, five 40-car trains per week do not have major impacts on rail traffic or service on the CSX, Inc. main line.

Also, following commencement of daily predictive modeling, the Plant is assumed to not have a major impact in terms of wait times for vehicular traffic at the on-grade rail crossing on the George Washington Parkway. Typical daytime rail operations (20-car trains) stop traffic on the Parkway for ten periods of about 2 minutes each week, while typical nighttime operations (40-car trains) stop traffic on the Parkway for five periods of about 4 minutes each week (Personal communication between D. Cramer, Mirant Corporation, and L.N. McCold, Oak Ridge National Laboratory, July 7, 2006).

Road. Under the Order before the commencement of daily predictive modeling (between December 20, 2005, and June 30, 2006), the Plant is estimated to have generated about 16 to 28 round trips each weekday (using 24-ton trucks) transporting ash from the Plant to the Brandywine facility. These trips had a negligible impact in terms of traffic on the local streets used to access the Plant, as the streets have relatively little traffic and operate at a level-of-service at or near “A” (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the addition of 16 to 28 truck trips to the existing traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6-1) represented only a small impact. However, the increase in traffic associated with operations between December 20, 2005, and June 30, 2006, contributed to the existing traffic problems on Maryland Route 381. (See the discussion in Section 3.6.2.)

Following commencement of daily predictive modeling (on July 1, 2006), including the temporary extension of the Order to December 1, 2006, and any extension beyond that date, the Plant is assumed to operate at a level similar to pre-shutdown operations, but with the addition of trona. Because the use of trona can approximately double the amount of ash produced, the Plant generates up to twice as much coal fly ash per day as under pre-shutdown operations (Section

4.3.6.1), requiring up to 56 round trips each weekday from the Plant to the Brandywine facility. Mirant is currently approved to deliver a total of 100 truckloads of ash to the Brandywine facility each weekday from the Potomac River Generating Plant and the Chalk Point Generating Plant combined (Baxter 2006).

Although the estimated level of truck traffic each weekday after July 1, 2006 (56 round trips), exceeds truck traffic under pre-shutdown operations (28 round trips), pre-Order operations (6 round trips), and operations between December 20, 2005, and June 30, 2006 (14 to 16 round trips), it does not appear to have a major impact in terms of traffic on the local streets used to access the Plant, since the streets have relatively little traffic and operate at a level of service at or near "A" (Personal communication between B. Garbacz, Transportation Engineer, City of Alexandria, Virginia, and J.W. Saulsbury, Oak Ridge National Laboratory, May 26, 2006). Similarly, the addition of about 56 truck trips to the existing traffic volume on the major roads between Henry Street and Maryland Route 381 (Table 3.6 1) represents a relatively minor impact in terms of traffic. The increase in traffic associated with operations after commencement of daily predictive modeling is, however, estimated to make a relatively large contribution to the existing traffic problems on Maryland Route 381. (See the discussion in Section 3.6.2.)

4.3.7 Environmental Justice

As discussed in Section 4.3.1, the elevated levels of air pollution from Plant operation that occur under certain conditions are highest very close to the Plant. Because of their proximity to the Plant, under all operating conditions residents of block groups 1 and 2 (Figure 3.7-1) experience higher exposures to air pollution from Plant emissions than residents of block groups 3 and 4. All of the gridded locations where maximum modeled ambient air concentrations occur (as reported in Tables 4.3.1-1 and 4.3.1-2) are located within block groups 1 and 2.

Thus, the populations with the highest exposure to impacts from the Plant are the non-minority and non-low-income populations in block groups 1 and 2. Consequently, the minority and low-income populations in block groups 3 and 4 (Section 3.7) do not experience "disproportionately high and adverse human health or environmental effects" related to air pollutant emissions from the Plant. In addition, DOE has not identified any different or unique ways that these or other minority and low-income populations in the area could be exposed to Plant air pollutants or otherwise affected by the Order or its potential extension. Thus, neither the Order nor any extension to the Order have "disproportionately high and adverse human health or environmental effects ... on minority and low-income populations" as discussed in Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*.

As discussed in Section 4.3.1, the elevated levels of air pollution from Plant operation that occur under certain conditions are highest close to the Plant. Thus, because of their proximity to the Plant, under all operating conditions residents of block groups 1 and 2 experience higher air pollution from Plant emissions than residents of block groups 3 and 4. Consequently, the minority and low-income populations in block groups 3 and 4 do not

experience “disproportionately high and adverse human health or environmental effects” related to air pollutant emissions from the Plant. In addition, these populations do not have different or unique ways of being affected by the Order or its potential extension.

5. ALTERNATIVES FOR FUTURE DECISION-MAKING

The DOE Order, as extended, expires on December 1, 2006. Before December 1, 2006, DOE will decide whether to allow the Order to expire, extend the Order, or take some other action, such as extending the Order with mitigation measures.

5.1 Allow the Order to Expire

As stated in the Order, Pepco's new 230-kV transmission lines are expected to provide a high level of electric reliability to the Central D.C. area even in the absence of production from the Plant. However, these new lines are not expected to be complete until the summer of 2007. DOE cannot speculate how Mirant would operate if DOE did not extend the Order; however, allowing the Order to expire would likely place the Central D.C. area in risk of a potential blackout.

It is difficult to specify the risk of death or health injury associated with blackouts because of the lack of statistical studies on such risk. However, blackouts can cause, and historically have caused, significant health and environmental impacts.

Blackouts create multiple public health problems that can lead to new or exacerbated injury or death. During hot weather blackouts can result in increased deaths, due to loss of air-conditioning or cooling ventilation. For example, 232 deaths were reported in the Midwest in the summer of 1999 during an extreme heat wave that also included a series of power disturbances; the majority of the deaths were attributable to elderly individuals without access to air-conditioning (Palecki and Changnon 1999). Blackouts can also cause significant problems for people with existing illnesses. During the Midwest/Northeast blackout of August 2003 paramedics from Passaic Beth Israel hospital had to respond to four times the usual number of calls, many involving respiratory ailments for patients whose batteries on home respirators had expired and for electronic breathing aids that went dead (WNBC 2003a).

Blackouts can also cause impacts to drinking water supplies and water bodies. The Midwest/Northeast blackout of August 2003 cut water service to 1.5 million people in Cleveland and caused officials in Detroit to warn residents to boil their water until the supply could be tested for potential bacteria (Water Quality and Health Council 2004). Because electricity powers pumps that push water through a city's water system, blackouts can cause the pressure in water pipes to drop, leaving the system open to bacteria entering the water supply. In addition, the discharge of sewage from treatment plants that run on electricity can cause environmental damage to water bodies. As recently as May 19, 2006, a 3-hr power failure at the Blue Plains Wastewater Treatment Plant in Washington, D.C. resulted in 17 million gallons (64,000 m^3) of raw untreated sewage being spilled into the Potomac River (Cohn 2006).

Blackouts also cause injury and death from fires (e.g. due to burning of candles), use of unvented portable emergency generators, accidents, and criminal activity. In the July 1977

blackout in New York City fires killed three, and one store owner shot and killed an armed looter (TIME 1977). Hundreds were also injured during widespread looting and other criminal activity in the July 1977 blackout. In a July 2006 blackout in Missouri that affected 150,000 people, a utility worker died after touching downed power lines, and another man died from burns while he tried to fix a generator he was using in his home (Associated Press 2006). In addition, during the Midwest/Northeast blackout of 2003 two people succumbed to carbon monoxide fumes from a gas generator aboard the boat they had been sleeping in overnight (WNBC 2003b).

5.2 Extend the Order as Currently Written

Impacts associated with extending the Order until either June 30, 2007, or December 31, 2007 (assuming a delay in installation of the new transmission lines), are assessed in Chapter 4. Extension of the Order until either date would result in increased impacts as compared to the Plant's "pre-Order" operating mode, but not the Plant's "pre-shutdown" operating mode. As presented in Chapter 4, impacts resulting from SO_2 emissions would be lower than under the pre-shutdown mode, while impacts resulting from trona use would be higher than under the pre-shutdown mode, and levels of other impacts would be similar to those from pre-shutdown operations.

5.3 Extend the Order with Mitigation Measures

Impacts of Plant operation under an extension of the Order could be mitigated by various alternatives including: (1) requiring Mirant to improve Plant operations and pollution control measures, (2) requiring Mirant to reduce exposure to pollutants to workers and nearby residents, (3) managing the demand for electricity in the Central D.C. area, (4) using alternative sources for generating electricity, and (5) expediting the installation of additional transmission lines.

5.3.1 Improve Plant Operations and Pollution Control Measures

- Require Mirant to store enough trona at or near the Plant to achieve 80% removal of SO_2 emissions for the full duration of any planned line outages. Mirant's experiments with trona indicate that this level of sulfur removal can be achieved. While Mirant has installed trona units on all five boilers, Mirant does not maintain sufficient trona on site or nearby to reduce emissions by 80% under high power operations for the duration of planned line outages.

    - Requiring Mirant to store sufficient trona at the Plant could help to ensure the logistical feasibility of achieving 80% removal of SO_2 emissions during a planned line outage, pursuant to the ACO. This could result in decreased modeled emissions

and any associated health effects. The quantity of trona available to Mirant may be limited, however, or it may take more time to increase current storage space at or near the Plant than required to install the two new transmission lines. DOE can consider working with EPA to monitor the ability of Mirant to gain and store enough trona for the Plant to achieve 80% SO_2 removal.

- Require that during non-outage situations Mirant operate the Plant at the minimum level of power generation that would maintain all units in a state in which they would be available to produce full power within a few hours of a line outage. Based on information provided by Mirant, minimum operation would require each baseload unit to operate 20 hours per day at minimum power (about 30 MW) and 4 hours at maximum power (about 105 MW). Similarly, the load-following or cycling units would need to operate 8 hours per day at minimum power (30 MW) and 4 hours at maximum power (88 MW).

    - This would reduce overall operation of the Plant and, therefore, reduce emissions and any associated health effects. DOE considered this operating mode before issuing the Order, but determined that it is not feasible because the baseload units at the Plant are designed for operation at high power levels and cannot sustain low levels of operation for a long period of time without damage.

- Require Mirant to increase the height of the Plant's exhaust stacks in order to create conditions conducive to better dispersion of emitted pollutants.

    - Taller stacks would reduce modeled air quality impacts of plant operations. The taller stacks would be visible at a greater distance and may also result in adverse visual impacts for neighbors of the Plant. Issues related to stack height increase are under the jurisdiction of the Federal Aviation Administration (FAA), which has granted Mirant permission to raise the stacks by 50 ft (15 m).

5.3.2 Reduce Exposure to Pollution

- Require Mirant to notify nearby residents when they would be potentially affected by a modeled NAAQS exceedance.

    - DOE is not able to estimate what people would do with such information and whether any decrease in health effects would occur. However, DOE can consider requiring Mirant to post daily when residents would be potentially affected by a modeled NAAQS exceedance during a line outage.

- DOE will post Mirant's monthly reports to EPA (as required by the ACO), as they become available to DOE, on DOE's website containing information related to the Plant. Such monthly reports would notify nearby residents of the results of monitored data, thereby allowing nearby residents to assess the likelihood of future exposure to an actual NAAQS exceedance.

- Pepco is filing monthly progress reports on the status of Pepco's new transmission lines and corresponding planned outages with FERC (FERC docket number EL05-145-000). Nearby residents can access Pepco's monthly reports through FERC's elibrary system at http//www.ferc.gov/docs-filing/elibrary.asp (search for FERC docket number EL-05-145-*).

  In addition, pursuant to the December 20, 2005, Order, Pepco is required to give advance notice of any planned outage and the estimated duration of any such outage to DOE. DOE will post any advance notice received from Pepco on DOE's website containing information related to the Plant (http://www.oe.energy.gov/permitting/372.htm).

  Therefore, nearby residents should be aware of planned line outage situations when the Plant is directed to produce power (up to full capacity) as directed by PJM.

- Require Mirant to provide the people who live in areas that would be affected by modeled exceedances of NAAQS during planned line outage situations the reasonable cost of moving to alternate locations until the threat of an exceedance is over if such people so choose.

  - Implementing this would involve several practical difficulties, such as determining the number of people who would be affected by a modeled exceedance, and whether relocation would be an appropriate response.

  - DOE believes that this many not be an appropriate use of its authority under Section 202(c) of the Federal Power Act (FPA) under these circumstances.

- Require Mirant to monitor outdoor levels of PM on the Plant site and provide suitable breathing protection for those working in high PM areas.

  - DOE can consider consulting with EPA about the need for PM monitoring. Determining the need for or type of suitable breathing protection is too speculative at this time.

5.3.3 Manage the Demand for Electricity in the Central D.C. Area

- Require the D.C. Public Service Commission (DCPSC) to develop a plan for reducing electrical demand in the Central D.C. area.

    - Reducing electrical demand in the Central D.C. area would reduce the need for operation of the Plant. However, the DCPSC and Pepco do not currently have a formal plan to reduce electrical demand in this area. Developing a plan would require rulemaking procedures, and implementing the plan would require infrastructure changes that may well take more time than required to install the new transmission lines. However, DOE has had several discussions with DCPSC encouraging DCPSC's efforts to reduce electrical demand in the Central D.C. area. DCPSC has informed DOE that:

        - DCPSC has given approval to Pepco to install "smart meters" in 2,250 homes as part of an effort to investigate how demand can be reduced in peak and other critical times.

        - DCPSC is currently in discussions with fellow state public service commissions in the Mid-Atlantic area and with PJM on how to improve demand response and related distributed energy resources.

        - A DCPSC commissioner is currently chairing the Mid-Atlantic Distributed Resources Initiative (http//www.energetics.com/madri/). DOE is currently providing technical advisory services and funding for facilitation efforts for this Initiative.

    - DOE can continue to encourage DCPSC to pursue demand-response initiatives in the Central D.C. area as in previous Orders.

- Order the development of specific, emergency load reduction programs to compensate for an unexpected loss of electricity generation or transmission capacity. For example, DOE could require emergency load shedding or load cycling for Federal and/or D.C. government buildings and/or other facilities during electrical emergencies.

    - Emergency load shedding or load cycling would reduce the need for operation of the Plant. DOE's Federal Energy Management Program is pursuing opportunities for energy management within the Federal government, both within and outside of emergency situations. Most recently, DOE and the General Services Administration held a workshop on April 26, 2006, on potential demand-response opportunities that

was attended by the majority of Federal electricity customers. The workshop educated Federal electricity customers on the reliability problems in the Central D.C. area and offered DOE technical assistance for demand-response initiatives.

5.3.4 Use Alternative Sources for Generating Electricity

- Require installation of temporary or back-up electricity generating equipment at specific facilities or government agencies to eliminate the need for the Mirant Plant.

    - Installation of temporary or back-up electricity generating equipment would not likely generate enough power to eliminate the need for the Plant. Alternative sources of electricity sufficient to eliminate the need for one or more units at the Plant could not be brought on line before the additional 230-kV power lines have been brought into service.

- Encourage Federal agencies in the Central D.C. area to operate on alternative sources of electricity, to reduce their peak electricity demand, or to develop a generating capability. For example, heating plants operated by the General Service Administration could be modified to cogenerate both heat and electricity, and essential government facilities could become capable of independently generating their own electricity in emergencies.

    - Alternative sources of electricity could reduce the need for the Plant and were discussed at DOE's April 2006 workshop described above. However, alternative sources of electricity sufficient to replace the Plant or eliminate the need for one or more units at the Plant could not be brought on line before the additional 230-kV power lines have been brought into service.

5.3.5 Expedite the Installation of Additional Transmission Lines or Encourage the Use of Other Existing Lines

- Expedite the installation of the two 230-kV transmission lines that Pepco is currently working on.

    - DOE has evaluated Pepco's construction schedule to make sure it is as efficient as possible. DOE can continue to monitor the construction and outage schedule to ensure, as much as possible, that the construction process remains on schedule and that any planned outages are essential. Pepco notified DOE on September 7, 2006, that the expected installation date of the new 230-kV lines is now June 21, 2007, instead of July 1, 2007.

- DOE can provide assistance to Pepco in expediting the installation of the new 230-kV lines that is requested by Pepco and that is practical and feasible. For example, at Pepco's request DOE met with Pepco representatives in March 2006 to discuss ways that DOE could help with the NEPA process for Pepco's proposed route for the new 69-kV lines to the Blue Plains Wastewater Treatment Plant (which partially fall on National Park Service land). The new 69-kV lines became operational on July 15, 2006.

- Encourage Pepco to construct additional new transmission lines, for example, from other plants in close proximity to the Central D.C. area, namely the Benning Road or Buzzard Point plants, to supply the power currently provided by the Plant.

    - Pepco already uses the power from these sources for other customers. Obtaining additional rights-of-way to construct new transmission lines would not be feasible in the time period required to solve the immediate reliability issues in the Central D.C. area.

- Encourage the use of additional transmission lines along existing corridors. Existing transmission lines enter the D.C. area from the north and south along, for example, railroad rights-of-way of the National Railroad Passenger Corporation ("AMTRAK") and CSX Corporation.

    - As described in Pepco's April 13, 2006, filing to DOE, although use of the existing transmission lines on the AMTRAK and CSX rights-of-way would reduce the need for the Plant in the Central D.C. area, the lines are already being used by Pepco. Adding additional lines along the same corridor would take more time than required to install the new 230-kV transmission lines already planned and under development.

- Encourage the use of currently existing, but inactive, transmission lines, such as the 69-kV circuits between Buzzard Point and the Plant.

    - As described in Pepco's April 13, 2006, filing to DOE, Pepco refurbished three 69-kV circuits between Buzzard Point and the Plant in 2004 to provide emergency back-up service, which would be used to restart the Plant and help the restoration process for any blackout of the Central D.C. area. These circuits cannot be energized under normal operating conditions because they are of small capacity and would overload quickly upon the failure of one of the existing 230-kV transmission circuits or the Plant; thus, their use would not provide an increase in reliability.

6. REGULATORY CONSULTATION AND COMPLIANCE

Under Section 7 of the Endangered Species Act (ESA) Federal agencies must consult with the Fish and Wildlife Service (FWS) or the National Marine Fisheries Service (NMFS) regarding actions that they may undertake that could adversely affect species and habitats protected under the Act. In order to comply with this requirement, DOE sent letters to FWS and NMFS as part of informal consultation describing the species that were likely to occur near the Plant and requesting concurrence from FWS and NMFS that the operation of the Mirant Potomac River Generating Station under the terms of the DOE Orders would not adversely impact Federally listed or proposed threatened or endangered species or designated or proposed critical habit. (See Appendix D.)

The responses from FWS and NMFS, also included in Appendix D, are discussed in Section 4.3.4.4.

7. REFERENCES[32]

Alliance for the Chesapeake Bay. Undated. http://www.alliancechesbay.org/index.cfm http://www.acb-online.org/about.cfm (Accessed June 1, 2006)

American Forests. 2002. Urban Ecosystem Analysis for the Washington D.C. Metropolitan Area. An Assessment of Existing Conditions and a Resource for Local Action. February. http://americanforests.org/downloads/rea/AF_WashingtonDC2.pdf (Accessed May 29, 2006)

Anacostia Watershed Network. 2006. http://www.anacostia.net/ (Accessed June 5, 2006)

Anacostia Watershed Restoration Committee. 2001. Aiming High, Setting Targets for a Restored Anacostia Watershed. 2001 Anacostia Watershed Restoration Agreement. December 3. http://www.anacostia.net/download/2001_Agreement_Color.pdf

Anacostia Watershed Restoration Committee. 2004. Working Together to Restore the Anacostia Watershed. Annual Report 2003. Washington, D.C.. http://www.anacostia.net/download/2003_annual_report_final.pdf (Accessed September 25, 2006)

Associated Press. 2006. "California Heat Wave Blamed in up to 90 Deaths." July 27. http://msnbc.msn.com/id/14003245/?GT1=8307 (Accessed September 25, 2006)

Azad, A.D., and T. Kitada. 1998. Characteristics of the air pollution in the city of Dhaka, Bangladesh in winter. *Atmospheric Environment* 32, No. 11, p. 1991-2005.

Baxter, Reggie. 2006. Technical Staff Report, Special Exception Application No. 4520, Extension of Time for the Operation of a Sanitary Landfill (Fly Ash). The Maryland-National Capital Park and Planning Commission, Prince George's County Planning Department, Upper Marlboro, MD. SE-4250. March 1. http://www.mncppc.org/pgco/planning/pdf/03-16-6/SE-4520.pdf

[32] Internet addresses (URLs) are provided for all items that are only available on the Internet as electronic documents, as well as for many items that are available as both electronic documents and conventional paper publications. Access dates are provided in all cases where the Internet content cited is potentially subject to revision but is not marked with a revision date.

Blankenship, Karl. 1997. Water Managers Urged to Add Their Concerns to Air Rules Debate. Chesapeake Bay Journal. April. http://bayjournal.com/article.cfm?article=1740 (Accessed April 7, 2006)

Blankenship, Karl. 2004. How Allocations Were Made. Chesapeake Bay Journal. March. http://www.bayjournal.com/article.cfm?article=1212 (Accessed April 7, 2006)

Boynton, W.R., and D. P. Swaney. 1998. N and P budget for the Chesapeake Bay. http://data.ecology.su.se/mnode/North%20America/chesapeake/chbbud.htm (Accessed June 7, 2006)

Brakebill, John W., and Steven D. Preston. 2004. "Digital Data Used to Relate Nutrient Inputs to Water Quality in the Chesapeake Bay Watershed, Version 3.0," U.S. Geological Survey, Baltimore, Maryland. Open-File Report 2004-1433.

Cada, Glenn F., J. Samuel Suffern, K. Deva Kumar, and Jean A. Solomon. 1981. Investigations of entrainment mortality among larval and juvenile fishes using a power plant simulator. Pp. 111-122. IN: *Issues Associated with Impact Assessment.* Edited by Loren D. Jensen. Proceedings of the Firth National Workshop on Entrainment and Impingement. San Francisco, CA, 5-7 May 1980.

Capacasa, Jon M. 2005. NPDES Permit No. DC0022004, Potomac River Generating Station, Administrative Extension of Current Permit. Letter to Hula C. Edmonds, Mirant Potomac River, LL. EPA, Philadelphia, PA. March 15.

CBP (Chesapeake Bay Program). Undated. http://www.chesapeakebay.net/index.cfm (and information linked from this page) (Accessed May 30 and June 20, 2006)

CBP. 2000. Air Pollutants and the Chesapeake Bay (slide presentation). http://www.chesapeakebay.net/pubs/airlink.ppt

CBP. 2005. Simulated Nutrient and Sediment Load Reductions (1985-2004). http://www.chesapeakebay.net/status/status_print.cfm and spreadsheet "npsedload.xls", updated November 1, 2005. (Accessed April 10, 2006)

CBP STAC (Chesapeake Bay Program Scientific and Technical Advisory Committee). 1996. "Ascertaining Sources of Nitrogen Entry to the Chesapeake Bay with Emphasis on Atmospheric Inputs," October. http://www.chesapeake.org/stac/Pubs/stac02_Nentry.pdf (Accessed April 7, 2006)

CBWP-MANTA (Chesapeake Bay and Watershed Programs. Monitoring and Non-tidal Assessment). 2001. Habitat Quality and Biological Integrity Assessment for the Northeast and Northwest Branches of the Anacostia River. CBWP-MANTA-EA-01-3. March. http://www.dnr.state.md.us/streams/pubs/ea01-3_anacostia.pdf (Accessed June 6, 2006)

CEQ (Council on Environmental Quality). 1997. Environmental Justice Guidance under the National Environmental Policy Act. Washington, D.C.. December 10.

10 CFR (Code of Federal Regulations) Part 1021. *National Environmental Policy Act Implementing Procedures.*

40 CFR 261.4. *Identification and Listing of Hazardous Waste; Exclusions.*

40 CFR Part 50. *National Ambient Air Quality Standards.*

40 CFR Part 61. *National Emission Standards for Hazardous Air Pollutants.*

40 CFR Part 62. *Approval and Promulgation of State Plans for Designated Facilities and Pollutants.*

40 CFR Part 63. *National Emission Standards for Hazardous Air Pollutants for Source Categories.*

40 CFR Parts 1500-1508. *Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act.*

Cohn, D'Vera. 2006. "Power Outage Unleashes Raw Sewage," *The Washington Post*, page B10. Washington, D.C, May 20.

DC WASA (District of Columbia Water and Sewer Authority). 2006. District of Columbia Water and Sewer Authority. http://www.dcwasa.com/ (Accessed June 2, 2006)

DCPSC (District of Columbia Public Service Commission). 2005. *Emergency Petition and Complaint of the District of Columbia Public Service Commission*, Docket No. EL05-145-000, as filed with the Department of Energy and the Federal Energy Regulatory Commission, August 24.

Dockery, D.W., C.A. Pope, X. Xu, J.D. Spengler, J.H. Ware, M.E. Fay, B.G. Ferris, and F.E. Speizer. 1993. "An Association Between Air Pollution and Mortality in Six U.S. Cities," *New England J. Med.* 329: 1753-1759.

DOE (U.S. Department of Energy). 2005. Order 202-05-03. [District of Columbia Public Service Commission Docket EO-05-01], Samuel W. Bodman, Secretary of Energy, Washington, D.C., December 20.

DOE. 2006. "Emergency Order to Resume Limited Operation at the Potomac River Generating Station, Alexandria, VA, in Response to Electricity Reliability Concerns in Washington, D.C." Notice of Emergency Action, 71 *Federal Register* 3279-3281. January 20.

Dvorak, A. J., B. G. Lewis, et al. 1978. Impacts of Coal-Fired Power Plants on Fish, Wildlife, and their Habitats. FWS/OBS-78/29. March.

Dyni, John R. 1991. Descriptive Model of Sodium Carbonate in Bedded Lacustrine Evaporites; Deposit Subtype: Green River (Model 35b.1). In: Some Industrial Mineral Deposit Models: Descriptive Deposit Models (G.J. Orris and J.D. Bliss, eds.), Open-File Report 91-11A, U.S. Geological Survey, Tucson, AZ.

Dyni, John R. 1996. Sodium Carbonate Resources of the Green River Formation. Open-File Report 96-279, U.S. Geological Survey, Denver, CO.

ENSR Corporation. 2005. *A Dispersion Modeling Analysis of Downwash from Mirant's Potomac River Power Plant*. Document No. 10350-002-410. August.

EPA (Environmental Protection Agency). 1995. Ecological Restoration. EPA 841-F-95-007. November. http://www.epa.gov/owow/nps/Ecology/ (Accessed June 6, 2006)

EPA. 1997. *An Environmental Characterization of the District of Columbia: A Scientific Foundation for Setting an Environmental Agenda* EPA-903-R-97-027. http://www.epa.gov/maia/html/dc_report.html (Accessed May 29, 2006)

EPA. 2000. "Potomac Estuary Case Study." Chapter 8 in *Progress in Water Quality: An Evaluation of the National Investment in Municipal Wastewater Treatment*. Office of Water. Washington, D.C.. EPA-832-R-00-008. June.

EPA. 2002. "User's Guide for the AMS/EPA Regulatory Model – AERMOD, draft," August.

EPA. 2004. "United States of American and the State of Maryland, Plaintiffs, and Robert G. Burnley, Director, Commonwealth of Virginia, Department of Environmental Quality, Plaintiff-Intervenor v. Mirant Potomac River, LLC and Mirant, Mid-Atlantic, LLC, Defendants; Consent Decree," September 27. http://www.epa.gov/compliance/resources/decrees/civil/caa/mirantcd.pdf (accessed August 18, 2006)

EPA. 2005. Methods for Projection Health Benefits for EPA's Multi-Pollutant Analyses of 2005. Office of Air and Radiation, October. http://www.epa.gov/airmarkets/mp/bmresults/health_benefits_method.pdf

EPA. 2006a. Acid Rain. http://www.epa.gov/acidrain/index.html (and information linked from this page) (Accessed June 8, 2006)

EPA. 2006b. "NOx SIP Call (NOx Budget Trading Program) Preliminary Summary Emission Reports," http://www.epa.gov/airmarkets/emissions/prelimsip/ March 22.

EPA. 2006c. Electricity from coal. http://www.epa.gov/cleanrgy/coal.htm (Accessed July 24, 2006)

EPA. 2006d. Ecological Resources Fact Sheet. http://www.epa.gov/maia/html/er-fact.html (Accessed May 29, 2006)

EPA. 2006e. Information on the Toxic Effects of Various Chemicals and Groups of Chemicals http://www.epa.gov/R5Super/ecology/html/toxprofiles.htm (Accessed August 19, 2006)

EPA. 2006f. *Currently Designated Nonattainment Areas for All Criteria Pollutants*, as of March 2, 2006. http://www.epa.gov/air/oaqps/greenbk/ancl.html#VIRGINIA (Accessed September 21, 2006)

EPA. 2006g. "United States of America and the State of Maryland, Plaintiffs, and David K. Paylor, Director, Commonwealth of Virginia, Department of Environmental Quality, Plaintiff-Intervenor v. Mirant Potomac River, LLC and Mirant Mid-Atlantic, LLC, Defendants, Amended Consent Decree." Civil Action No: 1:04CV1136, lodged May 8, 2006. http://www.epa.gov/compliance/resources/cases/civil/caa/mirant0406.html (Accessed September 20, 2006)

EPA. 2006h. “Fact Sheet: Implementation of New or Revised National Ambient Air Quality Standards for Particle Pollution,” http://www.epa.gov/air/particlepollution/fs20060203.html (Accessed September 20, 2006)

EPA. 2006i. “Fine Particle ($PM_{2.5}$) Designations Frequent Questions; Why haven't $PM_{2.5}$ nonattainment areas already been designated?” http://www.epa.gov/pmdesignations/faq.htm#7 (Accessed September 20, 2006)

EPA. 2006j. “National Ambient Air Quality Standards for Particulate Matter, Final Rule,” 40 CFR Part 50. 71 *Federal Register* 61144-61233. October 17.

Fairfax County Stormwater Planning Division. 2001. Fairfax County Stream Protection Strategy Baseline Study. Department of Public Works and Environmental Services. Fairfax, VA. January. http://www.fairfaxcounty.gov/dpwes/environmental/sps_pdf.htm (Accessed June 7, 2006)

FHWA (Federal Highway Administration). 2006. U.S. Department of Transportation, Federal Highway Administration. Transportation Conformity Reference Guide, Glossary. Revised March 2006. http://www.fhwa.dot.gov/environment/conformity/ref_guid/glossary.htm (Accessed October 16, 2006)

Fuller, Pam. 2006. *Channa argus*. U.S. Geological Survey Nonindigenous Aquatic Species Database, Gainesville, FL. http://nas.er.usgs.gov/queries/FactSheet.asp?speciesID=2265 Revised April 11.

FWS (Fish and Wildlife Service). 2006. Endangered Species Glossary. http://www.fws.gov/endangered/glossary.pdf (Accessed July 21, 2006)

Galli, John, Edward Graham, Timothy Murphy, Phong Trieu, Peter Guillozet, and Dave Shepp. 2001. Anacostia Watershed Restoration Indicators and Targets for the Period 2001-2010. Metropolitan Washington Council of Governments, Department of Environmental Programs. Washington, D.C. August. http://www.anacostia.net/download/indicators_and_targets.pdf

GB&B Inc. (Gershman, Brickner & Bratton, Inc.). 2005. Rubblefill Needs Assessment -- Ashfill of Mirant MD Ash Management LLC. May.

Hagy, James D., and Michael Kemp. 2002. Patuxent River, Maryland, USA. http://data.ecology.su.se/mnode/North%20America/chesapeake/Patuxent/patuxent_riverbudget.htm (Accessed June 7, 2006)

Harrison, David. 2004. “Fairfax Landfills Filling Up.” Connection Newspapers. May 13.

IPCC (Intergovernmental Panel on Climate Change). 2001. “Climate Change 2001: Synthesis Report, Summary for Policymakers.” http://www.ipcc.ch/ (Accessed August 8, 2006)

Jensen, Loren D., editor. 1981. Issues associated with impact assessment. Proceedings of the Fifth National Workshop on Entrainment and Impingement. San Francisco, CA, May 5-7, 1980.

Keeney, Timothy R. E. 2002. Testimony on the effect of Washington aqueduct discharges on the endangered shortnose sturgeon before the Committee on Resources, U. S. House of Representatives. June 19.

Kirby, Brendan, and John Kueck. 2005. “Washington D.C. Reliability Requirements and the Need to Operate Mirant’s Potomac River [Generating] Station to Support Local Area Reliability,” Oak Ridge National Laboratory, Oak Ridge, Tennessee, December. Redacted version at: http://www.oe.energy.gov/DocumentsandMedia/mirant_122905.pdf (Accessed July 13, 2006)

Marland, G., T.A. Boden, and R. J. Andres. 2006. *Global, Regional, and National CO2 Emissions.* In *Trends: A Compendium of Data on Global Change*. Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory, Oak Ridge, TN. http://cdiac.esd.ornl.gov/trends/emis/tre_glob.htm (Accessed August 8, 2006)

Maryland DNR (Department of Natural Resources). Undated-a. Patuxent River Basin. http://www.dnr.state.md.us/streams/pubs/patuxent.pdf (Accessed September 25, 2006)

Maryland DNR. Undated-b. Potomac-Washington Metro Basin. http://www.dnr.state.md.us/streams/pubs/potomacwashingtonmetro.pdf (Accessed September 25, 2006)

Maryland DNR. Undated-c. Tributary Strategies: Patuxent River Commission. http://www.dnr.state.md.us/bay/tribstrat/patuxent/patuxent.html and http://www.dnr.state.md.us/bay/tribstrat/patuxent/pr_status_trends.html (Accessed June 21, 2006)

MDOE (Maryland Department of Environment). 2005. Solid Waste Managed in Maryland, Calendar Year 2004. Annual Report to the Legislature. Baltimore, MD. September 1.

MDOE. 2006. Prioritizing Sites for Wetland Restoration, Mitigation, and Preservation in Maryland. Montgomery County. May 18. http://www.mde.state.md.us/assets/document/wetlandswaterways/MO.pdf (accessed August 19, 2006)

MDOT (Maryland Department of Transportation) 2005. Maryland's Traffic Volume Maps by County: Prince George's County Traffic Volume Map 2005. Maintained by the State Highway Administration. http://www.sha.state.md.us/shaservices/mapsbrochures/maps/oppe/trafficvolumemaps/2005/princegeorges.pdf (Accessed May 30, 2006)

MDOT. 2006. Projects. Maintained by the State Highway Administration. http://www.sha.state.md.us/businesswithsha/projects.asp?id=WD51+B170 (Accessed May 30, 2006)

Metropolitan Washington Council of Governments. 1999. Anacostia Restoration Agreement. http://www.anacostia.net/agreement.htm May 10.

Metropolitan Washington Council of Governments. 2001. "Waste Management Trends in the Washington Metropolitan Region 2001." Washington, D.C. November. http://www.mwcog.org/uploads/pub-documents/Dl5f20030624150406.pdf (Accessed September 11, 2006)

Metropolitan Washington Council of Governments. 2005. "Air Quality Trends, Metropolitan Washington, D.C. Region, 1993-2004." Department of Environmental Programs, Washington, D.C., August.

Mirant. 2002. Potomac River Generating Station Thermal Plume Study in 2001.

Mirant. 2006a. Potomac River Generating Plant. http://potomac.mirant.com/index.html (Accessed June 16, 2006)

Mirant. 2006b. Potomac River Generating Plant Water Quality. http://potomac.mirant.com/environment/waterquality.htm (Accessed June 16, 2006)

Mirant. 2006c. Trona Injection Tests, Mirant Potomac River Station Unit 1, November 12 to December 23, 2005. 21 pages. January 16. http://mirant.com/our_business/where_we_work/potomac.htm (Accessed November 7, 2006)

NatureServe. 2006. NatureServe Explorer: An online encyclopedia of life [web application]. Version 5.0. NatureServe, Arlington, Virginia. Available at http://www.natureserve.org/explorer (Accessed July 21, 2006)

NMFS (National Marine Fisheries Service). 1998. Final Recovery Plan for the Shortnose Sturgeon *Acipenser brevirostrum*. December. http://www.nmfs.noaa.gov/pr/pdfs/recovery/sturgeon_shortnose.pdf (Accessed June 19, 2006)

Northern Virginia Regional Commission. Undated. Occoquan Basin Nonpoint Pollution Management Program. http://www.novaregion.org/occoquan.htm (Accessed June 6, 2006.)

NPS (National Park Service). Undated. George Washington Memorial Parkway. http://www.nps.gov/gwmp/index.htm (Accessed May 29, 2006)

NPS. 2002. Study for the National Park Service: Facility & Site Analysis for a Boathouse on the Potomac River in Arlington County and Vicinity. August. http://www.nps.gov/gwmp/boathouse/chapters.htm (Accessed May 26, 2006)

Palecki, Michael A., and Stanley A. Changnon. 1999. The Nature and Impacts of the July 1999 Heat Wave in the Midwest. Midwestern Climate Center, Illinois State Water Survey. Champaign, IL. August 23. http://mcc.sws.uiuc.edu/climate_midwest/historical/hw99/hw99.html (Accessed September 25, 2006)

Palmer, Curtis A., Allan Kolker, Robert B. Finkelman, Kathleen C. Kolb, Stanley J. Mroczkowski, Sharon S. Crowley, Harvey E. Belkin, John H. Bullock, Jr., and Jerry M. Motooka. 1997. Trace Elements in Coal - Modes of Occurrence Analysis. DE-Al22-95PC95156. U.S. Geological Survey, Reston, VA. July 24.

Pepco. 1982. Impingement at the Potomac River Generating Station. 35 pages. August.

Pepco. 1983. Potomac River Generating Station Entrainment Study. 60 pages.

Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. “Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.” *Journal of the American Medical Association*. 287: 1132.

Roth, Nancy E., Mark T. Southerland, Ginny M. Rogers, and Jon H. Vølstad. 2005. Maryland Biological Stream Survey 2000-2004. Volume IV: Ecological Assessment of Watersheds Sampled in 2003. Maryland Department of Natural Resources (DNR) Publication # DNR-12-0105-0038. January. http://www.dnr.state.md.us/streams/pubs/ea05-1data03.pdf

Schreiber, R. K. 1995. Acidic Deposition ("Acid Rain"), pp. 418-420; In LaRoe, E.T., G. S. Farris, C. E. Puckett, P. D. Doran, and M. J. Mac. *Our Living Resources. A report to the Nation on the distribution, abundance, and health of U.S. plants, animals and ecosystems*. U.S. Dept. Interior, National Biological Service, Washington, D.C. 530 pp. http://biology.usgs.gov/s+t/frame/u204.htm (Accessed June 1, 2006)

Shanks, Kenneth (Primary Author and Editor). 2005. Characterization of the Anacostia River Watershed in Prince George's County, Maryland. Maryland Department of Natural Resources (DNR) Publication No. DNR-14-1209-0021. March. http://dnrweb.dnr.state.md.us/download/bays/ar_char_text_appa.pdf (Accessed June 9, 2006)

SPROL. 2005. Mirant Flips off Power Plant. August 28. http://www.sprol.com/?p=241 (Accessed May 29, 2006)

TFHRC (Turner-Fairbank Highway Research Center). Undated. User Guidelines for Waste and Byproduct Material in Pavement Construction. United States Department of Transportation Federal Highway Administration. http://www.tfhrc.gov/hnr20/recycle/waste/begin.htm (Accessed July 28, 2006)

TIME. 1977. "Night of Terror," *TIME Magazine*, July 25, pp. 12-22.

TRC Environmental Corporation. 2006. "Final Report; Particulate Emissions Testing, Unit 1, Potomac Generating Station, Alexandria, Virginia." (prepared for Mirant Potomac River, LLC.) Lowell, Massachusetts, January.

16 U.S.C. (United States Code) § 824 *et seq*. "Regulation of Electric Utility Companies Engaged in Interstate Commerce" under the *Federal Power Act*.

U.S. Census Bureau. 2006. American FactFinder. http://www.factfinder.census.gov

VDEQ (Virginia Department of Environmental Quality). 2002. Active Solid Waste Facilities in Virginia's DEQ Northern Regional Office. April 23. http://www.deq.state.va.us/waste/pdf/anvro.pdf (Accessed September 11, 2006)

VDEQ. 2005a. *Virginia Ambient Air Monitoring 2004 Data Report*. August. http://www.deq.virginia.gov/airmon/pdf/AnnualRpt04.pdf (Accessed September 11, 2006)

VDEQ. 2005b. "Motion of Robert G. Burnley, Director of the Commonwealth of Virginia Department of Environmental Quality to Deny the District of Columbia Public Service Commission's Petition on the Grounds that the Commission May Not Lawfully Grant the Requested Relief; or, in the Alternative, to Defer Action Pending Further Analysis of Environmental Impacts of Requested Relief," October 11, Before the Federal Energy Regulatory Commission, Docket No. EL05-145-000. http://www.oe.energy.gov/DocumentsandMedia/mirant_101205.pdf (Accessed September 20, 2006)

VDEQ. 2006a. 8-hour Ozone Nonattainment & Early Action Areas. http://www.deq.virginia.gov/air/status.html (Accessed July 28, 2006)

VDEQ. 2006b. $PM_{2.5}$ Nonattainment Area. http://www.deq.virginia.gov/air/status2.html (Accessed July 28, 2006)

VDEQ. 2006c. *Virginia Ambient Air Monitoring 2005 Data Report*. August. http://www.deq.virginia.gov/airmon/documents/AnnualReport05_002.pdf (Accessed November 15, 2006)

VDOT (Virginia Department of Transportation). 2004. 2004 Virginia Department of Transportation Daily Traffic Volume Estimates, Including Vehicle Classification Estimates Where Available: Special Locality Report 100, City of Alexandria. http://www.virginiadot.org/comtravel/resources/AADT_100_Alexandria_2004.pdf (Accessed May 26, 2006)

VDOT. 2006. Virginia Department of Transportation Projects By Region: Northern Virginia Projects. http://www.virginiadot.org/projects/district-projects.asp?ID=9 (Accessed May 26, 2006)

Virginia Department of Health. 2004. Health Statistics. http://www.vdh.virginia.gov/healthstats/ (Accessed August 28, 2006, and October 17, 2006)

VNHR (Virginia Natural Heritage Resources). 2006. Search for VA Natural Heritage Resources Information. http://192.206.31.52/cfprog/dnh/naturalheritage/display_counties.cfm (Accessed July 21, 2006)

Water Quality and Health Council. 2004. "Water in the Balance- A Boiling Crisis for the Nation's Water Supply," *Drinking Water & Health Quarterly* 10(1). http://www.waterandhealth.org/newsletter/new/winter_2004/water_balance.html (Accessed September 25, 2006)

Wearmouth, Ann. 2004. NPDES Renewal for Mirant Potomac River, Potomac River Generating Station - DC002204 (submittal to EPA Region III, Philadelphia, PA). Mirant Mid-Atlantic, LLC, Upper Marlboro, MD. October 19.

WebElements. 2006. Chemistry: WebElements Periodic Table: Professional Edition: Selenium: Key Information. The University of Sheffield and WebElements Ltd, UK http://www.webelements.com/webelements/elements/text/Se/key.html (Accessed August 4, 2006)

WHO (World Health Organization). 2000. "Air Quality Guidelines for Europe, Second Edition," World Health Organization Regional Publications, European Series No. 91.

Wilderness Society. Undated. Potomac River Watershed Facts. http://www.wilderness.org/Library/Documents/upload/Potomac-River-Watershed-Facts.pdf

WNBC. 2003a. "Respiratory Patients Flood N.J. Hospitals During Blackouts," August 17-18. http://www.wnbc.com/health/2410840/detail.html (Accessed September 25, 2006)

WNBC. 2003b. "No Power Woes Yet, But Will Lights Stay On?," August 18. http://www.wnbc.com/news/2411302/detail.html (Accessed September 25, 2006)

WWBP (Woodrow Wilson Bridge Project). 2006a. The Woodrow Wilson Bridge Project. http://www.wilsonbridge.com/ (Accessed May 30, 2006)

WWBP. 2006b. "Eagle Martha Put Down after Severe Injury," October 3. http://www.wilsonbridge.com/pdfs/pressReleases/pr2006-1002.pdf (Accessed October 16, 2006)

8. LIST OF PREPARERS

Department of Energy

Anthony J. Como, Office of Electricity Delivery and Energy Reliability. NEPA Document Manager

Oak Ridge National Laboratory

Lance N. McCold, Research Staff, Environmental Sciences Division
Technical Responsibilities: Team Leader, Meteorology, Air Quality
Education: B.S., 1973, Physics, Oregon State University
M.S., 1976, Mechanical Engineering, Oregon State University
Years of Experience: 27
Total Publications: 40

Kenneth W. Childs, Research Staff, Computational Sciences & Engineering Division
Technical Responsibilities: Air quality modeling
Education: B.S., 1971, Mechanical Engineering, University of Tennessee
M.S., 1974, Mechanical Engineering, University of Tennessee
Years of Experience: 35
Total Publications: 80+

John T. Jankovic, Industrial Hygiene Specialist, Safety Services Division
Technical Responsibilities: Human Health
Education: B.S., 1972, Environmental Health Science, Ferris State University
M.S.P.H., 1979, Industrial Hygiene and Safety Engineering, University of North Carolina
Years of Experience: 33
Total Publications: 15

Martha S. Salk, Research Staff, Environmental Sciences Division
Technical Responsibilities: Ecological Resources, Document Integration
Education: B.A., 1967, Biology, Albion College
M.S., 1969, Botany, University of Iowa
Ph.D., 1975, Plant ecology, University of Louisville
Years of Experience: 32
Total Publications: 40

James W. Saulsbury, Research Staff, Environmental Sciences Division
Technical Responsibilities: Transportation, Environmental Justice
Education: B.A., 1986, History, University of Tennessee
M.S., 1989, Planning, University of Tennessee
Years of Experience: 19
Total Publications: 30

Ellen D. Smith, Research Staff, Environmental Sciences Division
Technical Responsibilities: Water Resources, Waste Management
Education: B.A., 1974, Geology, Carleton College
M.S., 1979, Water Resources Management, University of Wisconsin-Madison
Years of Experience: 27
Total Publications: 27

Gregory P. Zimmerman, Research Staff, Environmental Sciences Division
Technical Responsibilities: Figures/Drawings/Graphic Arts; Document Review, Editing, and Composition
Education: B.S., Mechanical Engineering, 1975, University of Tennessee
M.S., Mechanical Engineering, 1977, University of Tennessee
Years of Experience: 29
Total Publications: 80+

[This page intentionally left blank]

APPENDIX A

DOE Emergency Orders

[This page intentionally left blank]

United States of America
Department of Energy

District of Columbia Public Service Commission) Docket No. EO-05-01

Order No. 202-05-3

I. Summary

Pursuant to the authority vested in the Secretary of Energy 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 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 meet the emergency and serve the public interest. Therefore, Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), are hereby ordered to generate electricity at their Potomac River Generating Station (the "Plant") pursuant to the terms of this order.

II. Procedural History

On August 19, 2005, Mirant submitted to the Virginia Department of Environmental Quality (DEQ) a computerized emissions modeling study Mirant had conducted of its Plant that indicated that emissions from the Plant caused or contributed to significant localized exceedances of the National Ambient Air Quality Standards (NAAQS).[1] Also on August 19, 2005, DEQ issued a letter to Mirant which requested "that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shut down of the facility." (emphasis in original). The letter asked Mirant to provide DEQ with a summary of the actions taken and the progress toward eliminating NAAQS exceedances by August 24, 2005. At midnight on August 21, 2005, Mirant reduced production of all units at the Plant to their minimum load, and at midnight on August 24, 2005, Mirant shut down all five of the generating units at the Plant.

On August 24, 2005, the District of Columbia Public Service Commission (DCPSC) filed an *Emergency Petition and Complaint* with both the United States Department of Energy (DOE or Department) and the Federal Energy Regulatory Commission (FERC or Commission) pursuant to the FPA. The DCPSC requested the Secretary of Energy to find that an emergency exists under section 202(c) of the FPA and to issue an order directing Mirant to continue

[1] The Clean Air Act, 42 U.S.C. § 7401 *et seq.*, authorizes the United States Environmental Protection Agency (EPA) to establish NAAQS, 42 U.S.C. §§ 7408-7409, and states that it is the responsibility of the states and local governments for assuring that they are attained, 42 U.S.C. §§ 7401(a)(3) and 7416.

operation of the Plant. The basis for the petition was that the shutdown of the Plant "...will have a drastic and potentially immediate effect on the electric reliability in the greater Washington, D.C., area and could expose hundreds of thousands of consumers, agencies of the Federal Government and critical federal infrastructure to curtailments of electric service, load shedding and, potentially, blackouts." The DCPSC requested that the Commission issue a similar order under sections 207 and 309 of the FPA. Numerous parties filed interventions and comments in response to DCPSC's emergency petition, as well as subsequent comments and responses.[2] Further, both FERC and DOE issued information requests to Mirant, the Potomac Electric Power Company (PEPCO), the company responsible for supplying electricity to retail customers in the District of Columbia, and PJM Interconnection, LLC (PJM), the grid operator responsible for the administration of the bulk power grid and electricity market in the region.[3] In addition to the DCPSC petition proceedings, DOE has hosted and participated in numerous conference calls and meetings to gather information on the shutdown of the Plant and its effect on the reliability of D.C.'s electricity system.[4]

III. Background

The coal-fired Mirant Plant, which began operation in 1949, is located in Alexandria, Virginia, and is capable of producing 482 megawatts of electricity primarily for delivery to Washington, D.C. The Plant consists of five generating units, two of which are cycling units that range in output from 35 MW to 88 MW, and three of which are baseload units that range in output from 35 MW to 102 MW. It is one of only three sources of electricity that serve the central business district of the District of Columbia, many federal institutions, the Georgetown area in D.C., as well as other portions of Northwest, D.C., and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Water Treatment Plant, the largest wastewater

[2] Several of these filings were only made in the FERC docket and not in DOE's docket. Even though a number of filers did not submit their comments in the DOE docket, the Department has, in the interest of rendering an appropriate and fully informed determination, reviewed all the filings in the FERC docket for any pertinent facts that will assist the Department in making its decision. Also, to the extent the filings contained analysis or legal arguments pertaining to the Department's 202(c) authority, they have been considered in the Department's decision making process.

[3] The data submitted contained Critical Energy Infrastructure Information and was submitted in both confidential and redacted versions, as defined in FERC's rules at 18 C.F.R. § 388.13. All information contained in this order is from public filings in the DOE and FERC dockets.

[4] The Administrative Procedure Act's prohibitions on ex parte communications in an adjudicatory proceeding, 5 U.S.C. § 557(d)(1), do not apply to DOE's 202(c) proceedings, because section 202(c) explicitly authorizes the Department to issue a 202(c) order "either upon its own motion or upon complaint, with or without notice, hearing, or report. . ." 16 U.S.C. § 824a(c).

treatment plant in the world.[5] The other two sources are two 230 kV lines that deliver electricity from other generating sources in the regional electric grid operated by PJM. Although there are other generating units in close physical proximity to the Central D.C. area, (e.g., the Benning Road and Buzzard Point generating facilities, which are dual-fueled oil and natural gas generating power plants, owned by PEPCO) there are no transmission lines that would allow delivery of power from these other units to reach the Central D.C. area. With regard to the sources of power that serve the Central D.C. area, PEPCO owns and operates the transmission lines, and PJM determines electricity demand.

Although Mirant shut down all of the Plant's generating units on August 24, 2005, it has since restarted unit number one which, the Department understands, is currently operating. Mirant is operating the unit on an 8/8/8 basis --- that is, in any given twenty-four hour period, the unit runs for eight hours at its maximum level of 88 MW, eight hours at its minimum level of 35 MW, and has eight hours when it does not run. DOE has been informed that both EPA and DEQ acknowledge that the operation of this unit in this manner does not result in any NAAQS exceedances. In addition, DOE understands that Mirant is taking other steps to increase production at the Plant in a manner which will be acceptable to DEQ and EPA.

PEPCO has applied to the DCPSC to construct two new 230 kV lines that would supply electricity to the Central D.C. area. In the same application, PEPCO has proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. PEPCO proposes having the two 69 kV lines installed by the summer 2006 peak season, and the two 230 kV lines installed in 18 to 24 months. The two existing 230 kV lines that supply the Central D.C. area would need to be temporarily taken out of service sequentially in order to connect the new lines to the Central D.C. area. Once completed, these lines apparently would provide a high level of electric reliability in the Central D.C. area, even in the absence of production from the Plant.

IV. Discussion

A. Reliability Issues

The Department has conducted an independent analysis of the electricity reliability situation in the Central D.C. area and has analyzed the Plant's role in ensuring a sufficiently reliable supply of electricity to that area. DOE's analysis was conducted by the Department's Oak Ridge National Laboratory. Under North American Electric Reliability Council standards, at a minimum, the power system must carry at least enough contingency reserves of electricity to cover the most severe single contingency. The standards require that an area's system always be operated with sufficient reserves to compensate for the sudden failure of the area's most important single generator or transmission line.

[5] For purposes of this order, the area supplied with electricity by these three sources will be referred to as the "Central D.C. area," and the retail customers in this area will be referred to as the "Central D.C. area customers."

Based on the fact that the Central D.C. area has only three sources of supply, the Plant and the two 230 kV transmission lines, the Department's analysis concludes that in order to maintain a minimally reliable electric power system, the Plant must be available to run when one of the 230 kV lines is out of service, because if the remaining line failed there would be no other source of electricity to serve the Central D.C. area load. In addition, the analysis concludes that if one of the 230 kV lines failed unexpectedly, enough generation must be started as rapidly as possible so as to be able to serve all of the Central D.C. area load as a contingency reserve in the event the other line were to fail. The analysis also indicates that the Plant should be operated in such a way as to minimize the amount of time needed to bring it into production.

PEPCO has asserted that:

> Absent the generating capacity of the Plant, if the two 230 kV transmission circuits into the [Central D.C. area] fail, there will be a blackout in much of the District of Columbia until the circuits are repaired or the Plant's generators are restarted and can operate at a level that matches load. All electric customers in Georgetown, Foggy Bottom and major portions of downtown Washington will be affected. The affected customers will also include Blue Plains wastewater treatment plant. It is PEPCO's understanding that within 24 hours of the loss of electric supply, Blue Plains will have no option but to release untreated sewage directly into the Potomac River, which would result in a significant adverse impact to human health, aquatic wildlife and other environmental resources. Affected customers will also include numerous hospitals, schools, universities, commercial buildings, and residential customers. Importantly, numerous federal facilities will lose power, including those critical to the security, safety, and welfare of the whole country, such as the FBI, the Justice Department, the State Department, the Federal Emergency Management Agency, the Department of the Interior, and the Department of Energy to name but a few.[6]

No commenter has disputed these statements by PEPCO, and they have been generally corroborated by DOE's own independent analysis; therefore, DOE will accept them as correct statements of fact. Further, the 230 kV lines do go out of service on occasion; since 2000, there have been 34 one-line outages for maintenance, and seven occasions where one of the lines has tripped unexpectedly. DOE has been informed that, prior to 2000, there were two occasions when both of the lines failed simultaneously.

B. Environmental Issues

Some commenters have asserted that the renewed operation of the Plant would result in NAAQS exceedances and a violation of the Clean Air Act, and that DOE could not issue a 202(c) order which would contravene the Clean Air Act (42 U.S.C. §§ 7401-7626). In response to this assertion, DCPSC, PEPCO and PJM contend that there were no actual monitored

[6] *See* Potomac Electric Power Company's Leave to Answer and Answer to Comments, FERC Docket No. EL05-145-000 at pages 2 & 3 (September 9, 2005).

exceedances of the NAAQS at the Plant during operation, and that operation of the plant at full power does not exceed the emissions limits contained in the Plant's operating permit and therefore the operation of the Plant pursuant to a DOE order would not violate the Clean Air Act. EPA has shared information with DOE regarding NAAQS modeled results and other environmental issues at the Plant. In response to the environmental concerns raised, this order seeks to minimize, to the extent reasonable, any adverse environmental impacts. Should EPA issue a compliance order directed to operation of the Plant, DOE will consider whether and how this order should conformed to such order.

Another assertion raised is that DOE cannot issue an order without complying with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 *et seq.* Responders to that assertion stated that NEPA review requirements do not apply because any order would merely require the Plant to operate in the manner and at the level it has historically operated, and thus is not a "major federal action" triggering NEPA. In addition, responders assert that "...the emergency nature of the relief sought in this case permits the [the Secretary] to act without conducting a NEPA analysis, even if it were required."[7] DOE has determined that the emergency circumstances here make it necessary to take action without performing a NEPA analysis. Indeed, in order for an order under FPA section 202(c) to be issued at all, the Secretary of Energy must determine that an emergency exists, and I have made that determination here. DOE has consulted with CEQ about alternative arrangements pursuant to 40 C.F.R. § 1506.11.

C. Other Issues

Commenters opposed to the issuance of a FPA section 202(c) order cited *Richmond Power & Light v. FERC*, 574 F. 2d 610 (D.C. Cir. 1978) as imposing a limit on the Secretary's authority to make an emergency finding under section 202(c). In *Richmond*, the New England Power Pool (NEPOOL) petitioned the Federal Power Commission (the Secretary's predecessor in exercising section 202(c) authority) for an order pursuant to FPA section 202(c) to have utilities east of the Mississippi River with excess electric generating capacity supply NEPOOL with that excess capacity. The request was based on fears of an oil shortage due to the 1973 Arab oil embargo. The Commission responded by holding a conference and a series of meetings which resulted in an agreement among the purchasing, transmitting and supplying utilities and participating state regulatory commissions. As a result of the agreement, NEPOOL moved to withdraw its petition, which the Commission allowed. Richmond Power & Light Company challenged the decision to allow the withdrawal and the court found that the Commission did not abuse its discretion in declining to issue an order under section 202(c), but rather settling on the temporary-voluntary agreement program reached by the interested parties. Instead of limiting its

[7] District of Columbia Public Service Commission Answer to Motion of the Virginia Department of Environmental Quality at page 24 (October 26, 2005), FERC Docket No. EL05-145-000. *See also* Answer of Potomac Electric Power Company and PJM Interconnection, LLC at page 18, (October13, 2005), FERC Docket No. EL01-145-000.

reach, *Richmond* underscores the discretionary nature of the Secretary's authority under section 202(c).[8]

Another case asserted to limit the Secretary's authority to issue an order under section 202(c) was *National Fuel Gas Supply v. FERC*, 909 F2d 1519 (D.C. Cir. 1990). In that case, National Fuel applied under section 7 of the Natural Gas Act (NGA), 15 U.S.C. § 717 *et seq.*, for a certificate of public convenience and necessity to allow it to make interruptible sales of natural gas. The Commission imposed a condition that National Fuel accept a blanket transportation certificate to provide open access transportation. The court ruled that the Commission was improperly using a NGA section 7 certificate condition in place of an individual or generic proceeding under section 5 of the NGA. The Department does not see the relevance of *National Fuel* here. I am using section 202(c) of the FPA for precisely the type of situation contemplated by section 202(c) of the FPA.

V. Decision

Section 202(c) of the FPA vests in the Secretary of Energy the authority to issue an order when "an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes...." 16 U.S.C. § 824a(c). DOE's regulations acknowledge that "[e]xtended 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 by these regulations." 10 C.F.R. § 205.371.

I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

---

[8] The facts in *Richmond* and in the current situation are very different. *Richmond* dealt with a wide regional or even national energy shortage situation, while we are considering electricity reliability in a discrete geographic area. The facts here more closely resemble those considered by the Federal Power Commission in *City of Cleveland, Ohio v. Cleveland Electric Illuminating Company*, 47 FPC 747 (1972). In that case, the City of Cleveland petitioned the Commission pursuant to section 202(c) to order an interconnection with Cleveland Electric Illuminating Company to provide services during shortages caused by outages of the City of Cleveland's generating facilities, or delays getting generation on line. The Commission found that the City of Cleveland had an emergency due to periodic shortages of generating facilities caused by outages and ordered the establishment of a 69kV temporary emergency interconnection between the electric systems of the City and Cleveland Electric Illuminating. Similarly, here DOE is ordering the Plant to provide electricity in certain limited situations.

More specifically, if the Mirant plant is not available to generate electricity and one of the two transmission lines serving the Central D.C. area goes out of service, the Central D.C. area would be served by only one transmission line. Should that remaining line fail for any reason, a blackout would occur in the Central D.C. area, potentially for an extended period of time. In fact, if one or both of the transmission lines could not be brought back into service immediately and the only source of energy for the Central D.C. area was the Mirant Plant, in the absence of today's order it would take several hours at a minimum to bring the Plant into full operation.

The outage of one of these two lines is not merely a theortetical possibility. On Friday, December 16, 2005, PJM informed DOE that on the previous night, "one of the two circuits critical to providing service to the District tripped. Continued [electric] service to certain load within the District was at that time entirely dependent on the remaining circuit." As a result, PJM requested dispatch of a second generating unit at the Plant, but Mirant refused to do so. PJM informed DOE that "service was not interrupted because load was low and the remaining circuit performed without incident." Fortunately, full service to the line that had tripped was restored by the morning of December 16. Nonetheless, there can be no assurance that the Central D.C. area will be so lucky next time, either with respect to the timing of the event, the operation of the second transmission line, or the ability to bring the first transmission line back into service.

Furthermore, it is periodically necessary for an outage to occur on one of the transmission lines because of the need to perform maintenance. In fact, maintenance is scheduled on one of the lines in the next few weeks. Thus, as occurred on the night of December 15, 2005 and as will certainly occur again in the future, if the Mirant Plant is not made operational Central D.C. will find itself relying solely on one transmission line. The duration of an outage can range from up to several days (for maintenance) or even longer (up to weeks) if the outage of a line is due to a major equipment failure. Throughout such a period, if the Plant is not fully operational a blackout in Central D.C. is only one step away, i.e., if an event should occur that causes the second line to fail. Such a blackout could last for hours or days.

I recognize that, if past experience is any guide, the simultaneous failure or outage of both transmission lines serving the Central D.C. area is not a high probability. While this event has occurred in the past, it has not happened often. Moreover, the recent tripping of one circuit does not in itself dictate the existence of an emergency justifying issuance of a 202(c) order.

The facilities and functions that would be adversely affected by an extended blackout in this instance, however, is an important consideration. The Central D.C. area includes offices, facilities and operations involved in all three branches of government, and that are critically important to the Nation's national security, law enforcement and regulatory functions. The Central D.C. area also includes hundreds of thousands of residents and workers, and all manner of public safety and protection facilities, including hospitals, police, and fire facilities. Moreover, DOE has been informed that within 24 hours of a blackout in the Central D.C. area, untreated sewage from the Blue Plains Wastewater Treatment plant would be discharged into the Potomac River.

Finally, it is noteworthy that a blackout in the Central D.C. area not only would affect critically important facilities and operations, it could last for an extended period. Depending on the reason for the outage of the transmission lines, the lack of service on those lines accompanied by the lack of generation by the Plant could result in a large portion of the District of Columbia being without electricity for a period that could last hours or days. At the very least, if the two transmission lines were made unavailable with no advance notice and the only source of electricity for the Central D.C. area was the Mirant plant, in the absence of today's order DOE understands it would take at least 28 hours, and likely longer, to bring the Plant into full operation, during which time all or a substantial part of the Central D.C. area would be without electric power The results would be hardship and physical risk to hundreds of thousands of persons from loss of heat, elevator outages, medical equipment failure and numerous other causes. In addition, critical portions of the nation's government would also be severely impacted, with resulting adverse effects on a national scale.

Of course, the fact that the Department did not act immediately on the DCPCS petition does not argue against my finding that an emergency currently exists. After the petition was filed, DOE took several weeks to gather the relevant information, consider the facts, talk with environmental regulatory authorities, and develop an order that balanced the appropriate considerations. As explained in the text of this order, the current facts fully justify my finding that an emergency exists and that this order will meet that emergency. There certainly is nothing in the Federal Power Act that requires me to wait until a blackout actually has occurred, lives are put in jeopardy, and a significant disruption of National government functions already has happened before exercising my section 202(c) authority.

Accordingly, and based on all of the facts and circumstances, I find that an emergency exists justifying the issuance of this order under Federal Power Act section 202(c).

After finding the existence of an emergency, DOE has the authority, "either upon its own motion or upon complaint, with or without notice, hearing, or report, to order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). The statute gives the Secretary of Energy broad discretion to fashion the terms of an order that will, in the Secretary's judgment, "best meet the emergency and serve the public interest." Based on the circumstances described above in this order, I hereby direct Mirant to generate electricity at the Plant pursuant to the terms of this order.

While I am issuing this order to help ensure a reliable supply of electric energy to the Central D.C. area, I am cognizant of the concerns that have been expressed concerning the potential adverse environmental consequences of operating the Plant, and of the national interest in attainment of the NAAQS that have been established under the Clean Air Act. Ordering action that may result in even local exceedances of the NAAQS is not a step to be taken lightly. However, it would not be reasonable for the Department of Energy to stand by and take no positive action on the DCPSC petition, even though the Central D.C. area is in danger of an extended blackout and the Department and private parties have available to them the legal and operational tools to prevent such a blackout from occurring. In this order, I have sought to harmonize those interests to the extent reasonable and feasible by ordering Mirant to operate in a

manner that provides reasonable electric reliability, but that also minimizes any adverse environmental consequences from operation of the Plant.

DOE expects that the DCPSC, having sought an emergency order, will take such actions as are within its authority to provide adequate and reliable electric service for the Central D.C. area including, for example, expediting approval of PEPCO transmission system upgrades and instituting demand response programs.[9] Indeed, DOE views this order not as a permanent solution to the Central D.C. area's reliability issues, but rather as a bridge between the current untenable situation and a more permanent solution that must be crafted by appropriate parties, including the DCPCS, FERC, environmental regulatory authorities, and relevant private sector parties. This permanent solution may include the installation of the new transmission lines discussed above, the installation of new pollution control equipment at the Mirant Plant, or other means.

As explained above, in the event that one of the two transmission lines that serve the Central D.C. area is out of service (due either to a necessary planned outage or to unforeseen events) and sufficient electricity from the Mirant power plant were not available, then the Central D.C. area would experience an immediate blackout should the one remaining source of electricity fail. This situation must be avoided, and ordering paragraph A of this order ensures that this situation will be avoided. When an outage is planned, Mirant is to be given advance notice and is required to supply necessary generation throughout the period of the outage.[10] In the event of an unexpected outage, Mirant must provide such generation as soon as possible. In the very unlikely eventuality of both transmission lines failing at the same time, Mirant is required to provide sufficient generation to supply the electrical demands of the affected area as soon as possible.

It is essential to determine the level of operation and other steps that will enable Mirant to rapidly respond to an unplanned transmission line outage. Some commenters have urged the Department to order the Plant to run continuously, even if doing so causes ongoing exceedances of the NAAQS. This would assure a high level of reliability of the electricity supply, but of course would not be tailored to particular circumstances in which operation of the Plant would be most necessary to provide needed reliability for the Central D.C. area and might also cause local air quality concerns. Other commenters have urged the Department to do nothing.

---

[9] Demand response programs prompt electricity customers to reduce demand, especially during periods of short supply.

[10] In making certain portions of this order effective only upon notice to Mirant by PEPCO of a planned or unplanned outage of one or both of the 230 kV lines, it is similar to the FPA section 202(c) orders issued during the 2000/2001 California energy crisis. In those, DOE ordered certain entities to generate, deliver, interchange and transmit electricity to the California Independent System Operator (California ISO), but the entities were not required to deliver energy or services unless the California ISO had filed with DOE a certificate that it had been unable to acquire adequate supplies of electricity in the market. *See* Order pursuant to Section 202(c) of the Federal Power Act (December 14, 2000); Order Pursuant to Section 202(c) of the Federal Power Act (January 11, 2001).

The Department is not prepared to order actions that could cause more localized NAAQS exceedances than are necessary in order to assure adequate electric reliability for the Central D.C. area. At the same time, the Department should address the risks that delays in responding to an unplanned transmission line outage would present if measures are available to mitigate that risk. In my judgment, the appropriate balance is struck by (1) requiring Mirant to keep as many units in operation, and take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electrical reliability, as feasible (as further defined in the ordering paragraphs below). Thus, Mirant must take actions to reduce the time it takes to respond to an unplanned outage. This will serve to reduce the risk of a blackout but not at the price of unnecessary exceedances of health-based NAAQS. As Mirant improves its environmental performance, in cooperation with environmental regulators, its ability to react to an unforeseen outage also will improve. Environmental regulators and Mirant can work together, with the Department, to reduce, and perhaps eliminate, any conflict between environmental goals and electric reliability.

This order is effective immediately and will terminate at 12:01 a.m. October 1, 2006. This order may be modified or extended at any time upon order of the Secretary of Energy.

VI. Ordering Paragraphs

For the reasons set forth above, pursuant to section 202(c) of the Federal Power Act, it is hereby ordered that:

A. During any period in which one or both of the 230kV lines serving the Central D.C. area is out of service, whether planned or unplanned, Mirant will operate the Potomac River Generating Plant to produce the amount of power (up to its full capacity) needed to meet demand in the Central D.C. area as specified by PJM for the duration of the outage.

> In the event of a planned outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand.
>
> In the event of an unplanned 230 kV line outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand as soon as possible.

When producing electricity pursuant to this paragraph, Mirant shall utilize pollution control equipment and measures to the maximum extent possible to minimize the magnitude and duration of any exceedance of the NAAQS.

B. Mirant shall keep as many units in operation, and shall take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electricity reliability, as "feasible." For purposes of this paragraph, "feasible" means as determined by the Department of Energy, after consideration of the plan submitted by Mirant pursuant to paragraph D of this order and after consultation with the Environmental Protection Agency, without regard to cost and without causing or significantly contributing to any exceedance of the NAAQS.

C. Notice

In instances of scheduled outages of one of the 230kV lines, PEPCO will give advance notice of the planned outage and the estimated duration of such outage to Mirant, PJM, DOE, FERC, EPA, and DEQ. The notice must be sufficiently in advance of the outage to allow Mirant to bring the required amount of generation needed for reliability purposes on line by the time the outage is scheduled. PEPCO will ensure that only those planned outages needed to maintain or enhance the reliability of the 230 kV lines (or to install new lines) are scheduled and that such outages are scheduled to minimize the environmental effects of the operation of the Plant.

PEPCO will notify DOE, PJM, FERC, EPA, and DEQ of any unplanned outage of one or both of the 230 kV lines as soon as possible, but in no event later than two hours after informing Mirant.

In the event of either a planned or unplanned outage, PJM will specify the amount of electricity that Mirant must provide in order to meet demand.

D. Mirant shall submit a plan to DOE, within 10 days of the date of this order, detailing the steps it will take to ensure compliance with this order. This compliance plan shall include, at minimum, information regarding adequate staffing, materials, and supplies; emissions controls; and length of time necessary to start-up the Plant's generating units in the event of an unplanned or planned outage. DOE will review the compliance plan and order additional requirements if necessary.

E. Pursuant to the terms of FPA section 202(c) and DOE regulations at 10 C.F.R. § 205.376, Mirant and its customers should agree to mutually satisfactory terms for any costs incurred by Mirant under this order. If no agreement can be reached, just and reasonable terms shall be established by a supplemental order.

F. DOE expects that the DCPSC will take all reasonable actions to augment electrical reliability and to reduce electricity demand in the Central D.C. area.

G. DOE will periodically reexamine the need for this order with particular emphasis on: (1) Mirant's progress, working with environmental regulators, in reducing emissions and/or the impact of emissions; and (2) whether the DCPSC is taking all reasonable actions available to it to support electricity reliability in the Central D.C. area.

H. Pursuant to section 313 of the Federal Power Act (16 U.S.C. § 8251), any person, State, municipality, or State commission that is a party to this proceeding and is aggrieved by this order may apply for a rehearing within thirty days. Requests for rehearing may be submitted by mail, facsimile, or electronic mail to the following: (1) mail should be directed to Lawrence Mansueti of the Permitting, Siting, and Analysis Division of the Office of Electricity Delivery and Energy Reliability at the United States Department of Energy, Routing Symbol OE-20, 1000

Independence Avenue, S.W., Washington, D.C. 20585; (2) facsimiles may be submitted to 202-586-5860; (3) e-mail may be submitted to Lawrence.Mansueti@hq.doe.gov.

Issued in Washington, D.C. at _____ this 20th day of December, 2005.

Samuel W. Bodman
Secretary of Energy

Department of Energy

Washington, DC 20585

District of Columbia Public Service Commission

Docket No. EO-05-01

Order No. 202-06-2

On December 20, 2005, in Order No. 202-05-3, I determined that an emergency existed in the Central District of Columbia area 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 the order would serve to alleviate the emergency and serve the public interest. Therefore, pursuant to the authority vested in the Secretary of Energy 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 (DOE) Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth in Order No. 202-05-3, I ordered Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC, to generate electricity at its Potomac River Generating Station (the Plant) pursuant to the terms of the order.

In Order No. 202-05-3, I noted that the Plant is one of only three sources of electricity that serve the central business district of Washington, D.C., many federal institutions, and the Georgetown area, as well as other portions of Northwest D.C., and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Wastewater Treatment Plant. The order further noted that:

> PEPCO has applied to the [District of Columbia Public Service Commission] to construct two new 230 kV lines that would supply electricity to the Central D.C. area. In the same application, PEPCO has proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. PEPCO proposes having the two 69 kV lines installed by the summer 2006 peak season, and the two 230 kV lines installed in 18 to 24 months. The two existing 230 kV lines that supply the Central D.C. area would need to be temporarily taken out of service sequentially in order to connect the new lines to the Central D.C. area. Once completed, these lines apparently would provide a high level of electric reliability in the Central D.C. area, even in the absence of production from the Plant.

The two 69 kV lines to the Blue Plains wastewater treatment plant have been completed. The two new 230 kV lines have been approved by the relevant regulatory authorities and are scheduled to be completed and in operation by mid-summer 2007.

Printed with soy ink on recycled paper

On January 18, 2006, DOE issued a notice of the emergency order (published in the Federal Register on January 20, 2006, 71 FR 3279) in which DOE stated that it would prepare a Special Environmental Analysis (SEA) pursuant to the Council on Environmental Quality's Regulations Implementing the Procedural Requirements of the National Environmental Policy Act. The SEA would examine the potential impacts of the operation of the Plant pursuant to Order No. 202-05-3. DOE said it would make the SEA publicly available and would consider information contained in the SEA, and public comments on the SEA, in any future decision making regarding the operation of the Plant. The SEA has not yet been issued, but DOE expects it to be completed shortly.

Because the reliability problems identified in Order No. 202-05-3 continue in the absence of the completion of the two new 230 kV lines, but the SEA has not been completed, I am issuing a short-term extension of the emergency order pending completion and consideration of the SEA and DOE's review of comments thereon.

The Department reiterates its expectation that the DC Public Service Commission pursue demand response initiatives and actively promote conservation as additional means of enhancing reliability in the central D.C. area.

On February 17, 2006, I issued Order No. 202-06-1, which granted certain requests for rehearing of Order No. 202-05-3 for the limited purpose of further consideration. The rehearing requests continue under consideration and no action is being taken on those requests by the issuance of this order.

Based on the above, I find that the circumstances which led to my previous determination that an emergency existed still continue, and therefore I hereby extend Order No. 202-05-3 and all the terms and conditions thereof until 12:01 a.m., December 1, 2006.

Issued in Washington D.C. at 6:00 PM this 28 day of September, 2006.

Samuel W. Bodman
Secretary of Energy

APPENDIX B

EPA's Administrative Compliance Order for the Mirant Potomac River Generation Station

[This page intentionally left blank]

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

In the Matter of:

Mirant Potomac River LLC
Potomac River Generating Station
Alexandria, Virginia

Docket No. CAA-03-2006-0163DA

ADMINISTRATIVE COMPLIANCE ORDER BY CONSENT

I. STATUTORY AUTHORITY

This Order is issued pursuant to Section 113(a)(1) of the Clean Air Act (the "Act"), 42 U.S.C. § 7413(a)(1). Under Section 113(a)(1) of the Act, the Administrator of the United States Environmental Protection Agency ("EPA" or "the Agency") has the authority to issue Orders requiring persons to comply with the requirements of an applicable State Implementation Plan ("SIP") or permit issued by a state. The Administrator has delegated his authority to issue such Orders within the geographical jurisdiction of EPA Region III to the Regional Administrator of EPA Region III, who has re-delegated this authority to the Director of the Air Protection Division of Region III. The geographical jurisdiction of EPA Region III includes the Commonwealth of Virginia.

This Order is issued to Mirant Potomac River, LLC ("Mirant") for its Potomac River Generating Station in Alexandria, Virginia.

II. FINDINGS OF FACT

1. Mirant owns and operates an electricity generating station known as the Potomac River Generating Station ("PRGS") in Alexandria, Virginia.

2. Mirant is a Limited Liability Company organized in the State of Delaware on August 2, 2000.

3. Pursuant to the Order By Consent entered into by Mirant and the Virginia Department of Environmental Quality ("VaDEQ"), effective September 23, 2004, Mirant performed a

Dispersion Modeling Analysis to assess the effect of Downwash (the "downwash study") of emissions from the PRGS. The downwash study used computer modeling to predict ambient concentrations of pollutants emitted by the PRGS under certain weather and atmospheric conditions.

4. Mirant provided the results of the downwash study to VaDEQ in August 2005. By letter dated August 19, 2005, VaDEQ informed Mirant that the downwash study demonstrated that emissions from the PRGS result in, cause or substantially contribute to, modeled violations of the primary National Ambient Air Quality Standards ("NAAQS") for sulfur dioxide ("S02"), nitrogen dioxide ("NO2"), and PM10 under certain atmospheric conditions.

5. VaDEQ's August 19th letter also requested that Mirant immediately undertake "such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station." VaDEQ cited 9 VAC 5-20-180(I) as the authority for this action.

6. The provision of the Virginia State Implementation Plan ("SIP") cited by VaDEQ, 9 VAC 5-20-180(I), has been approved and incorporated into the Virginia SIP at 40 C.F.R. § 52.2420(c), and is therefore federally-enforceable.

7. Mirant shut down all five Units of the PRGS at midnight on August 24, 2005.

8. On August 24, 2005, the District of Columbia Public Service Commission ("DCPSC") filed an "Emergency Petition and Complaint" with the United States Department of Energy ("DOE") and the Federal Energy Regulatory Commission ("FERC"), respectively, pursuant to the Federal Power Act ("FPA"), 16 U.S.C. § 824a(c), 824f and 825h, and Section 301(b) of the DOE Organization Act, 42 U.S.C. § 7151(b). The Emergency Petition requested that DOE find that an emergency exists under Section 202(c) of the FPA and issue an order requiring Mirant to continue operation of the PRGS.

9. Following additional modeling and assessment of the downwash study, Mirant re-started Unit 1 of the PRGS on September 21, 2005. Additional modeling conducted by Mirant indicated that operation of only Unit 1 would not cause any modeled NAAQS exceedances.

10. On December 20th, 2005, the Secretary of Energy issued Order No. 202-05-3 ("DOE Order") finding that an emergency did exist and ordering Mirant to, among other things, submit a plan to DOE detailing the steps to be taken to ensure Mirant's compliance with the DOE Order.

11. On December 30, 2005, Mirant submitted to DOE the Operating Plan setting forth the steps that Mirant would take to ensure compliance with the DOE Order.

12. By letter dated January 4, 2006, DOE required that Mirant "immediately take the necessary steps to implement Option A of the intermediate phase proposed in the [Operating Plan]." The DOE letter also noted that implementation of Option A was an interim measure.

13. In accordance with DOE's directive to maximize electric generation while not causing or contributing to a NAAQS violation, Mirant supplemented the original Operating Plan with additional operating configurations and modeling. The supplements contemplated that Mirant would use trona injection and a blend of low sulfur coal to manage SO2 emissions. Mirant stated that these supplemental operating scenarios result in no modeled NAAQS exceedances.

14. By letter dated December 22, 2005, EPA issued a Notice to Mirant and the VaDEQ, alleging that Mirant did not immediately undertake the necessary action to protect human health and the environment required by VaDEQ's August 19, 2005 letter, and that Mirant was therefore in violation of 9 VAC 5-20-180(I) and the federally-enforceable Virginia SIP for the period of time in which it failed to immediately shut down all the PRGS Units.

15. Following issuance of the Notice, EPA met with Mirant on several occasions to discuss settlement of EPA's possible enforcement action for the violation alleged in the Notice under Section 113 of the CAA. These discussions, along with discussions with DOE and VaDEQ, have resulted in this Order.

16. In its evaluation of potential PRGS operating scenarios, DOE has determined that the levels of PRGS operation allowed under the terms and conditions of Part IV of this Order are necessary to assure an acceptable level of electric reliability to the District of Columbia under the circumstances.

17. EPA will require use of the AERMOD model with a 24 hour background SO2 concentration of 51 micrograms per cubic meter ("ug/m3") when evaluating the PRGS's effects on the SO2 NAAQS. In Mirant's December 30, 2005 Operating Plan and subsequent submissions to DOE and EPA, Mirant has used varying background concentrations for SO2 in determining the maximum predicted impact of various operating scenarios at the PRGS. EPA has determined that Mirant's use of these varying background concentrations was technically defensible but that additional conservatism will be required in this Order. In an effort to build additional conservatism into Mirant's operating scenarios to ensure protection of the NAAQS, EPA has instructed Mirant to use a background concentration of 51ug/m3 to add to the AERMOD 24 hour SO2 modeled pollutant concentrations to determine the maximum predicted impacts for all operational scenarios considered during and incorporated into this Order.

18. EPA has determined through modeling and analysis that there is a strong correlation between the days, hours, and locations of predicted highest 24-hour concentrations of

SO2 and predicted highest 24-hour concentrations of PM10; that the predicted highest concentrations of SO2 are higher, relative to the SO2 NAAQS, than the predicted highest concentrations of PM10 relative to the PM10 NAAQS; and that measures taken to reduce SO2 emissions from the PRGS facility, such as reduced levels of operation and/or increased levels of trona usage, will also reduce emissions of PM10.

III. CONCLUSIONS OF LAW

19. Mirant is a "person" within the meaning of Section 302(e) of the CAA, 42 U.S.C. § 7602(e), and within the meaning of Section 113(a) of the CAA, 42 U.S.C. § 7413(a), because it is a corporation.

20. EPA concludes that Mirant violated 9 VAC 5-20-180(I) by failing to immediately shut down the boilers at the PRGS upon receipt of the letter from VaDEQ, and that such failure is also a violation of Section 113(a) of the CAA, 42 U.S.C. § 7413(a).

21. Mirant has had an opportunity to confer with the Administrator or his designee regarding this alleged violation and the terms of this Order. Mirant denies that any violation occurred, but agrees to the entry of this Order.

22. EPA has determined that the following schedule and plan for compliance is reasonable, taking into account the seriousness of the modeled NAAQS exceedances and the concerns of DOE regarding electric reliability in the Central D.C. area, and that this schedule is expeditious given the length of time it will take Mirant to take more permanent measures as well as the time it will take for additional electric transmission lines to be put into service to alleviate the emergency as determined by DOE.

IV. ORDER

Based upon the forgoing, under Section 113(a)(4) of the Act, 42 U.S.C. § 7413(a)(4), IT IS DETERMINED AND ORDERED that:

A. Definitions - For the purpose of this Order, the following terms shall have the meanings defined below:

3-Hour Rolling SO2 and 24-Hour Calendar Day SO2 Emission Rate. For the purpose of calculating the specified rate in Table 1 for a specified time period, the actual SO2 emission rate is determined by dividing the sum of the total pounds of actual SO2 emissions from the boiler stack of that unit, as determined by hourly CEMS data, as certified by 40 CFR Part 75, by the sum of the total heat input in million Btus from that coal-fired boiler unit.

For any 3 hour rolling period when there are fewer than 2 hours of actual emissions from a coal-fired boiler unit, an emission rate for that 3 hour period that would have to comply with the Table 1 emission rates does not need to be calculated for that unit.

For any calendar day when there are fewer than 3 hours of actual emissions from a coal-fired boiler unit, a 24 hour emission rate to comply with Table 1 need not be calculated for that unit.

On any day when a unit runs between 3 and 18 hours, the complying 24 hour emissions rate for Table 1 shall be calculated as follows:

If a unit operates between 3 hours and 10 hours, the SO2 limit for that unit equals the 3 hour rate in Table 1 minus 1/3 of the difference between the 3 hr and 24 hr rate for that unit configuration;

If a unit operates 10 hours or more up to 18 hours, the SO2 limit for that unit equals the 3 hour rate in Table 1 minus 2/3 of the difference between the 3 hr and 24 hr rate for that unit configuration.

If a unit operates 18 hours or more, the 24 hour rate in Table 1 shall apply.

Nothing in this paragraph is intended to allow greater operation of a unit than what is specified in Table 1 where this Order requires operation in accordance with Table 1. In addition, where this Order requires operation in accordance with Table 1 and that configuration calls for unit(s) to operate between 3 and 18 hours, then the Table 1 emission rates shall apply without the above adjustments.

AERMOD Default means Version 04300 of the AERMOD computer model, currently approved for general use by EPA.

AERMOD EBD means the AERMOD computer model with modified direction-specific building dimensions derived from the Wind Tunnel Study.

Alternative Operating Scenario means a method of operating the Potomac River Generating Station during the Model Evaluation Study, which has been approved by EPA and reviewed by VaDEQ.

DOE means the United States Department of Energy

DOE Order means Order No. 202-05-3, issued by the Department of Energy on December 20, 2005 in Docket No. EO-05-01 in response to an Emergency Petition and Complaint filed by the District of Columbia Public Service Commission.

EPA means the United States Environmental Protection Agency, Region III.

Line Outage Situation means that one or both 230 kV transmission lines, serving the Central D.C. area are out of service due to a planned or unplanned outage.

Mirant means Mirant Potomac River, LLC.

Modeled NAAQS Exceedance means a modeled 3-hour average sulfur dioxide concentration which, when a background concentration of 238.4 micrograms per cubic meter is added, exceeds 1,300 micrograms per cubic meter; or a modeled 24-hour average sulfur dioxide concentration which, when a background concentration of 51 micrograms per cubic meter is added, exceeds 365 micrograms per cubic meter; or, a modeled 24 hour PM10 concentration which, when a background concentration of 45 micrograms per cubic meter is added, exceeds 150 micrograms per cubic meter.

Model Evaluation Study or MES means a study proposed by Mirant and approved by EPA and reviewed by VaDEQ to compare multiple computer model predicted ambient air impacts to actual measured ambient air concentrations for the purpose of determining the best performing computer model in evaluating the effects of the emissions resulting from the operation of the PRGS.

Monitoring Plan means a plan proposed by Mirant and approved by EPA and reviewed by VaDEQ as part of the MES for the installation and use of ambient air monitors in the vicinity of the PRGS to monitor ambient air quality impacts of the PRGS.

Monitors means the ambient air monitors installed in accordance with the Monitoring Plan.

NAAQS means the National Ambient Air Quality Standards.

Non-Line Outage Situation means all periods of time that do not qualify as a Line Outage Situation.

Operating Parameters means the hourly average MW load of each unit for each hour of that day at the PRGS, the hourly average SO2 emission rate expressed in lb/MMBtu for each unit for each hour of that day, and the emission rate of PM10 expressed in lb/MMBtu.

Operating Plan means the December 30, 2005 Operating Plan submitted to DOE by Mirant to respond to the requirement for a compliance plan under the DOE Order.

Predictive Modeling means the daily use of an approved AERMOD computer model run in accordance with 40 C.F.R. Part 51, Appendix W, with forecasted weather conditions and planned Operating Parameters for the following day to predict modeled NAAQS compliance on a day-ahead basis.

PJM means the regional transmission organization for the region where the PRGS is located.

PRGS means the coal-fired electric generating station owned by Mirant and located in Alexandria, VA, comprised of three baseload generating units (Units 3, 4, 5) of approximately 102 MW each and two cycling units (Units 1 and 2) of approximately 88 MW each.

VaDEQ means the Virginia Department of Environmental Quality.

Wind Tunnel Study means a study proposed by Mirant using a physical model, as outlined in CPP Wind's Wind Tunnel Model Evaluation protocol, dated January 17, 2006, reviewed by EPA and VaDEQ, and conducted in accordance with EPA Guidance, to evaluate the accuracy of AERMOD Default's assumptions with respect to the direction-specific effective building dimensions when applied to the PRGS.

B. **Operation During Non-Line Outage Situations**

1. Mirant shall implement and comply with all of the single-unit, two-unit, and three-unit configuration constraints listed in Table 1 below until such time as Mirant is authorized by EPA and DOE to begin an alternative operating scenario as described below. Mirant shall operate each unit within the applicable hours-of-operation and SO2 emission rate restrictions listed in the table each calendar day. Generally, unit transitions and unit startups will occur within (+/-) four hours of midnight. The following procedures will be followed when there is a transition between operating scenarios:

a. When transitioning between two units, the unit that is coming offline will cease burning coal before the starting unit begins burning coal. Number 2 oil will be burned during the warm-up phase of the starting unit and during the shutdown phase of the unit coming offline. The number of boilers burning coal will not exceed at any time the constraints applicable to the Unit Configurations listed in Table 1.

b. When a change in operating Unit Configuration occurs, Mirant shall, for the balance of the calendar day, meet the more stringent of the 3-hour SO2 and/or 24-hour SO2 rate caps and hours of operation applicable to:

(i.) the Unit Configuration being ceased, and
(ii.) the Unit Configuration being commenced.

TABLE 1

Unit Configuration	24 Hr Calendar Day SO2 Rate - Lb/MBtu	3-Hr Rolling SO2 Rate - lb/MBtu	Operating Constraints
Unit 1	1.20	1.20	8 hrs max / 8 min / 8 off, 14,800 lb/day
Unit 1	0.84	1.14	None
Unit 2	0.41	0.73	None
Unit 3	0.31	0.66	None
Unit 4	0.36	0.70	None
Unit 5	0.61	0.90	None
Units 1 & 2	0.29	0.50	Both Units: 100% Load 24 hrs/day
Units 1 & 3	0.24	0.51	#1 @ 8 max / 8 min / 8 off, none on #3
Units 2 & 3	0.23	0.40	#2 @ 8 max / 8 min / 8 off, none on #3
Units 1 & 4	0.30	0.54	#1 @ 8 max / 8 min / 8 off, none on #4
Units 2 & 4	0.25	0.44	#2 @ 8 max / 8 min / 8 off, none on #4
Units 1 & 5	0.43	0.60	#1 @ 8 max / 8 min / 8 off, none on #5
Units 2 & 5	0.35	0.55	#2 @ 8 max / 8 min / 8 off, none on #5
Units 3 & 4	0.23	0.43	#3 @ 6 max / 18 min; #4 @ 7 max /17 min
Units 3 & 5	0.24	0.43	Both units @ 12 hr max / 12 hr min
Units 4 & 5	0.27	0.51	Both units @ 12 hr max / 12 hr min
Units 1, 2 & 3	0.21	0.36	#1&2 @ 5 max / 4 min / 15 off, none on #3
Units 1, 2, &4	0.24	0.35	#1&2 @ 6 max / 5 min / 13 off, none on #4
Units 1, 2, &5	0.27	0.42	#1&2 @ 8 max / 8 min / 8 off, none on #5

2. Schedule for Installation of Trona Injection at All Boiler Units

a. In accordance with the schedule set forth in Mirant's Operating Plan of December 30, 2005, Mirant shall ensure that Trona injection units are installed and operated as follows:

(1). March 20, 2006 - In addition to the two portable, rental Trona units, Mirant shall have a third operational Trona injection unit, whether an engineered unit or a rental unit. Mirant shall operate all three Trona units whenever three or more boilers are operating.

(2). April 28, 2006 - Mirant shall have installed and be operating three engineered Trona injection units, and shall operate each unit whenever the boiler to which it is attached is operating. Mirant shall operate the rental Trona units on boilers not equipped with operating engineered units.

(3). May 31, 2006 - Mirant shall have installed and be operating

all five engineered Trona injection units, and shall operate each unit whenever the boiler to which it is attached is operating.

3. **Model Evaluation Study**

a. Mirant shall undertake a Model Evaluation Study to determine the best performing model for predicting the computer-modeled ambient air quality impacts from the PRGS's operations. Prior to beginning the MES, Mirant must submit to EPA for approval an MES protocol, and simultaneously send a copy to VaDEQ. Mirant may begin operating the PRGS in a manner that does not cause or contribute to Modeled NAAQS Exceedances by using Predictive Modeling as described in subsection 4 below, after completing the following tasks:

(1). EPA approval of the MES protocol;
(2). installation and operation of at least 3 SO2 monitors in accordance with the approved monitoring plan;
(3). execution of this Order by EPA; and
(4). authorization by DOE for Mirant to operate in accordance with this Order.

b. Upon commencement of daily predictive modeling performed in conjunction with the MES, the SO_2 emission rate limitations and other unit operating restrictions set forth in Table 1 shall no longer apply unless otherwise indicated. The Table 1 restrictions apply if Mirant ceases to operate the PRGS in accordance with the MES.

4. **Operations in Accordance with Daily Predictive Modeling**

a. By 10 AM each morning, Mirant shall collect actual weather predictions from the National Weather Service for the Reagan National Airport and use them along with planned Operating Parameters as inputs to conduct a computer modeling run for the following day using AERMOD Default. If the modeling confirms that Mirant's planned operations for the following day will not cause or contribute to a Modeled NAAQS Exceedance, Mirant may operate on the day modeled in accordance with the modeled Operating Parameters. If the Predictive Modeling indicates that the planned Operating Parameters will result in one or more Modeled NAAQS Exceedances, Mirant shall not run under those operating parameters but shall continue to adjust its planned operations and conduct additional modeling runs using the adjusted Operating Parameters to confirm that the adjusted operations will not cause or contribute to a Modeled NAAQS Exceedance for the day modeled.

b. During Line Outage Situations, Predictive Modeling must continue to be performed but the PRGS shall be operated under the Line Outage Situation provision in accordance with the DOE Order and this Order.

c. If the Predictive Modeling indicates that the predicted weather conditions and planned Operating Parameters do not result in a Modeled NAAQS Exceedance,

Mirant is authorized to operate using the planned Operating Parameters and shall not be in violation of this Order; or 9 VAC 5-20-180(I), as incorporated into the Virginia SIP at 40 C.F.R. 52.2420(c); nor shall such operation be deemed to give a right for a cause of action for any alleged violation of the NAAQS as a result of Mirant causing or contributing to any modeled or monitored exceedance of the NAAQS. This release shall only apply to alleged exceedances or violations occurring during the lifetime of the Order or the duration of the MES if the requirements of this Order have been incorporated into a state operating permit; shall only apply to laws in existence on the effective date of the Order; and shall not prevent Virginia from issuing an order under 9 VAC 5-20-180(I) or EPA from taking action under Section 303 of the Clean Air Act.

5. **Operation During Certain Periods of Elevated SO2 Impacts After MES Approval**

a. As a precaution, after the installation of at least three monitors, Mirant shall institute additional measures that will apply whenever ambient concentrations of SO2 are elevated, as defined below. Specifically, Mirant shall:

(1). Install a monitor alert system in the Potomac River Control Room that registers an audible alarm if in any one hour the average measured ambient concentration of SO2 at any monitor is equal to or greater than 80% of the 3 hour SO2 National Ambient Air Quality Standard, measured as 400 parts per billion (1,040 $\mu g/m^3$).

(a). During the hour following the sounding of the alarm, Mirant shall make operational adjustments, which may include increasing Trona injection and/or decreasing operation and shall observe the effect of these adjustments on the average, measured ambient concentration of SO2.

(b). If, at the end of the second hour, the average measured ambient concentration of SO2 is not equal to or less than 1,040 $\mu g/m^3$, Mirant shall adjust its operations to conform to the scenarios described in Table 1 until the rolling 3 hour average is less than 1,040 $\mu g/m^3$.

(2). Mirant shall also configure the audible alarm to sound if, in any 12 hour period, any monitor measures an average, ambient concentration of SO2 equal to or greater than 80% of the 24 hour SO2 National Ambient Air Quality Standard, measured as 112 parts per billion (292 $\mu g/m^3$).

(a). During the following 6 hours, Mirant shall make operational adjustments, which may include increasing Trona injection and/or decreasing operation and shall observe the effect of these adjustments on the measured ambient concentration of SO2.

(b). If, at the end of the 6 hour period, the average, measured ambient concentration of SO2 is not equal to or less than 292 $\mu g/m^3$, Mirant shall adjust its operations to conform to the scenarios described in Table 1 for the balance of the calendar day.

(3). Mirant shall also configure the audible alarm to sound if, after the first 6 months of operation, any monitor measures an average, ambient concentration of SO2 equal to or greater than 80% of the annual average NAAQS, measured as 64 $\mu g/m^3$.

(a). During the following 3 months, Mirant shall monitor the 7 month, 8 month and 9 month averages.

(b). If, at the end of 9 months, the average, measured ambient concentration of SO2 is not equal to or less than 64 $\mu g/m^3$, Mirant shall adjust its operations so that the annual, measured ambient concentration of SO2 does not exceed 80 $\mu g/m^3$.

(4). If the audible alarm sounds more than 5 times in a calendar month, Mirant shall, on a one-time basis, adjust the alarm to 75% of the applicable NAAQS.

6. **PM10 Predictive Modeling**

Whenever Mirant operates 4 or more units, it shall abide by an emission rate of 0.055 lbs/MM Btu and shall first conduct Predictive Modeling using this rate to determine whether operation of the units causes or contributes to a Modeled NAAQS Exceedance. If the Predictive Modeling indicates that the planned Operating Parameters will result in a Modeled NAAQS Exceedance for PM10, Mirant shall adjust its planned operating scenario and re-run the Predictive Modeling with an emission rate of 0.055 lbs/MM Btu until such time as Mirant confirms through Predictive Modeling that the adjusted operations will not cause or contribute to a Modeled NAAQS Exceedance for PM10.

7. **AERMOD EBD - Physical Changes Requiring Model Changes**

If Mirant elects to refine the AERMOD Default model by performing a Wind Tunnel Study, Mirant will submit a Wind Tunnel Study evaluation protocol for review by EPA and VaDEQ and approval by EPA. The protocol will describe the technical features of the proposed Wind Tunnel Study and the theoretical basis for demonstrating that the data generated should be used to develop a site-specific set of assumptions, including equivalent building dimensions, to be applied to AERMOD Default.

The results of the Wind Tunnel Study shall be submitted to EPA for approval and may result in site-specific equivalent building dimensions to be used in lieu of the assumptions in the AERMOD Default model. The results must be submitted to EPA no later than 90 days following entry of this AO. Upon approval of AERMOD EBD by EPA and VaDEQ, Mirant shall operate for the balance of the MES study period applying AERMOD EBD in its Predictive Modeling.

As the Model Evaluation Study progresses, Mirant may make other changes at the PRGS, including physical changes such as changes to the stacks. In that event, inputs utilized during the Predictive Modeling and in the models evaluated at the conclusion of the Model Evaluation Study (and the model used to develop emission limits for the PRGS) may, after EPA

approval, be adjusted to correspond to these changes. However, the MES study period must be conducted for a minimum of six months following any physical change in order to obtain monitoring data upon which to evaluate the models.

8. Monitoring and Comparison Modeling During the Model Evaluation Study

In accordance with the MES Protocol, as attached, Mirant shall install and operate a total of six (6) ambient SO2 monitors in the preferred locations or alternate locations as described below:

a. Preferred locations

(1). Two monitors on the roof of Marina Towers, with one located on the Southeast wing and one at the center of the building;

(2). One monitor east of the PRGS, approximately due east of Stack 5 on the west bank of the Potomac River;

(3). One monitor southeast of the PRGS, along the facility fenceline, near the River;

(4). One monitor approximately 800 meters north of Marina Towers; and

(5). One monitor on the roof of a building in the Harbor Terrace complex three

EPA will work with Mirant to assist in obtaining permission needed to install monitors in these preferred locations.

b. Alternate Locations: If EPA determines that notwithstanding Mirant's good faith and reasonable efforts to obtain permission to install monitors in the preferred locations, it is impractical to install some or all of the monitors in the preferred locations in a timely manner because the owner of the preferred monitor location declines to host the SO2 monitor(s) or the preferred location is unavailable or impractical for any other reason, EPA will authorize installation of monitors at some or all of the five alternative SO2 monitor locations set forth in the MES Protocol, as summarized below:

(1) Southwest of the PRGS on the rooftop of Braddock Place;
(2) Approximately 600 meters South-Southeast of the stack locations, at ground level along the Potomac River;
(3) Approximately 300 meters Southwest of the PRGS at ground level;
(4) Approximately 600 meters South-Southwest of the PRGS at ground level; and

(5) Approximately 100 meters SW of the plant at ground level.

c. Deadline for ambient monitor installation: Mirant shall have all six monitors installed and operating within 60 days of the execution of this Order. EPA may, at its own discretion, extend the deadline, and/or change locations, for installation and/or operation of one or all of the monitors and in the event that EPA determines that one of the preferred locations is impractical and authorizes use of an alternate location, Mirant shall have an additional 30 days in which to install that monitor.

d. Operation, Maintenance, and Quality Assurance/Quality Control ("QA/QC") of monitors - It shall be the responsibility of Mirant to ensure that the monitors are operated, maintained, and subject to the appropriate QA/QC provisions set forth at Appendix A to 40 C.F.R. Part 58.

e. Follow-up modeling: The data generated by the monitors shall be used at the end of the study to conduct a model evaluation. Until such time as all the ambient air monitors are installed in accordance with the Monitoring Plan and begin measuring and recording ambient air data, Mirant shall perform "follow up" computer modeling using actual weather conditions and Operating Parameters, and shall report the results to EPA and VaDEQ on a monthly basis, as described below. This "follow-up" modeling will be performed on the Monday following the previous week of operation.

9. **Determination of Best Performing Model at Conclusion of Model Evaluation Study**

At the conclusion of the MES, the performance of the applicable models will be evaluated in accordance with the document "Protocol for Determining the Best Performing Model." EPA-454/R-92-025, Sept. 1992, Comparing Computer Model-Predicted Air Concentrations to Actual Ambient Air Concentrations Measured by the Monitors. The information yielded by the comparison of model predictions to measured ambient concentrations will result in a determination by EPA and VaDEQ as to which model is best-performing. Thereafter, the best-performing model shall be used to conduct computer modeling to develop permanent emission limits at the PRGS.

10. **Reporting**

a. Throughout the period of the MES, Mirant shall deliver to EPA and VaDEQ monthly: (1) the modeled input files and results of the daily Predictive Modeling for the preceding month, including the hourly average heat input in MMBtu for each unit and the exit velocity (or exhaust volume) for each unit; (2) verification that the planned Operating Parameters utilized for Predictive Modeling in the preceding month were not exceeded, or if exceeded, documentation describing that exceedance; (3) the inputs and results of "follow-up" modeling for the preceding month (or portion thereof during which all Monitors were not in place), including the hourly average heat input in MMBtu for each unit and the exit velocity (or

exhaust volume) for each unit, but only until commencement of operation of all Monitors, and; (4) after installation of the Monitors, the data generated by the Monitors.

b. If at any time the "follow-up" modeling demonstrates a modeled exceedance of the NAAQS or the Monitors demonstrate an actual exceedance of the NAAQS, Mirant shall report such modeled or monitored exceedance to EPA and VaDEQ within 3 days of the modeled or monitored exceedance for a determination as to whether corrective action is required.

C. **Operation During Line Outage Situations**

1. During a Line Outage Situation, Mirant shall operate the PRGS to produce the amount of power needed to meet the load demand in the Central D.C. area, as specified by PJM and in accordance with the DOE Order. During such operations, Mirant shall take all reasonable steps to limit the emissions of PM10, NOX and SO2 from each boiler, including operating only the number of units necessary to meet PJM's directive and optimizing its use of Trona injection to minimize SO2 emissions. During a Line Outage Situation, Mirant shall achieve 80% reduction of SO2 emissions unless: 1) Mirant demonstrates, through predictive modeling or otherwise, that 80% reduction is not necessary to achieve compliance with the NAAQS; or 2) Mirant demonstrates that 80% reduction is not logistically feasible because of factors such as the quantity of available Trona and predicted duration of the outage. In the event that Mirant demonstrates that 80% reduction is not logistically feasible, it shall submit a plan to EPA for optimizing its use of Trona injection so as to maximize SO2 reduction and the plan shall propose control measures and removal efficiencies to be achieved during the Line Outage Situation. If Mirant has 30 days notice in advance of the Line Outage Situation, it shall submit the plan to EPA for approval 15 days before commencement of the Line Outage. If Mirant has less than 30 days advance notice of the Line Outage Situation, Mirant shall submit the plan to EPA for approval as promptly as reasonably possible under the circumstances. It is understood and acknowledged that the plan to be followed for an unscheduled Line Outage Situation will depend upon the specific circumstances at the time of the unscheduled Line Outage Situation. Nothing here shall diminish Mirant's obligation to produce the amount of power needed to meet the load demand in the Central D.C. area, as specified by PJM, and in accordance with DOE's Order.

2. Malfunctions of emission control devices, such as Trona injection, shall not be deemed a failure to limit the emissions during a line outage, provided that Mirant has made reasonable efforts to avoid the malfunction and to promptly correct the malfunction. All emissions during a Line Outage Situation count toward any other permit, statutory, or regulatory limits for the PRGS. Upon Mirant's request, EPA (after consultation with DOE) will provide contemporaneous written confirmation of the existence of a Line Outage Situation. If Mirant operates the PRGS in accordance with dispatch directions from PJM and the relevant terms of this Order during a Line Outage Situation, Mirant shall not be in violation of this Order; or 9 VAC 5-20-180(I), as incorporated into the Virginia SIP at 40 C.F.R. 52.2420(c); nor shall such operation be deemed to give a right for a cause of action for any alleged violation of the

NAAQS as a result of Mirant causing or contributing to any modeled or monitored exceedance of the NAAQS. This release shall only apply to alleged exceedances or violations occurring during the lifetime of the Order or the duration of the MES if the requirements of this Order have been incorporated into a state operating permit; shall only apply to laws in existence on the effective date of the Order; and shall not prevent Virginia from issuing an order under 9 VAC 5-20-180(l) or EPA from taking action under Section 303 of the Clean Air Act.

D. General Provisions

1. At all times, Mirant shall not emit more than 3700 tons of NOx per year and shall limit the emission rate of PM10 to 0.055 lbs/MMBtu.

2. Mirant's actions shall be consistent with all provisions of federal and state law, including but not limited to, the Clean Air Act, all federal regulations promulgated under the Clean Air Act, and any other applicable laws, including the Virginia State Implementation Plan.

E. Permitting Requirements

Within the 12 month period following entry of this Order, Mirant must cooperate with VaDEQ in the development of operating permit emission limits protective of all NAAQS. Mirant agrees that the obligations of this Order, to the extent they have not been completed, may become obligations in the operating permit issued by VaDEQ. Mirant further agrees that during the implementation of this Order, it will prepare and submit to EPA and VaDEQ an analysis of the applicability of NSR/PSD to the PRGS due to the installation of Trona injection and any additional fugitive emissions resulting from that installation.

V. PARTIES BOUND

This Order shall apply to and be binding upon Mirant, its agents, successors, and assigns and upon all persons, contractors and consultants acting under or for Mirant, or persons acting in concert with Mirant who have actual knowledge of this Order or any combination thereof with respect to matters addressed in this Order. No change in ownership or corporate or partnership status will in any way alter Mirant's responsibilities under this Order.

In the event of any change in ownership or control of the PRGS, Mirant shall notify the EPA in writing at least thirty (30) days in advance of such change and shall provide a copy of this Order to the transferee-in-interest of the PRGS, prior to any agreement for transfer.

VI. RESPONSES TO ORDER

Information required to be submitted to EPA under this Order must be sent to:

Chief, Air Enforcement Branch
Air Protection Division,

U.S. Environmental Protection Agency, Region 3
1650 Arch St.
Philadelphia, PA 19103

And

Douglas J. Snyder
Assistant Regional Counsel
Office of Regional Counsel (3RC10)
U.S. Environmental Protection Agency, Region 3
1650 Arch St.
Philadelphia, PA 19103

VII. EFFECT OF COMPLIANCE ORDER

As set forth in Section 113(a)(4) of the Act, 42 U.S.C. § 7413(a)(4), nothing in this Administrative Compliance Order by Consent shall prevent EPA from assessing any penalties, or otherwise affect or limit the United States' authority to enforce other provisions of the Act, or affect any person's obligations to comply with any Section of the Act or with any term or condition of any permit or applicable implementation plan promulgated or approved under the Act. Further, nothing in this Order shall limit or otherwise preclude the United States from taking criminal or additional civil judicial or administrative enforcement action against Mirant or any third parties with regard to the PRGS pursuant to any other federal or state law, regulation or permit condition, or for Mirant's failure to comply with any requirements of this Order. Nothing herein shall be construed to limit the authority of the EPA to undertake action against any person, including Mirant, in response to any condition that EPA determines may present an imminent and substantial endangerment to the public health, public welfare or the environment. EPA reserves any rights and remedies available to it to enforce the provisions of this Order, the Act and its implementing provisions, and of any other federal laws or regulations for which it has jurisdiction following the entry of this Order.

For the purposes of this proceeding only, Mirant hereby expressly waives its right to any appeal of this Order which it may have under Section 307(b) of the CAA, 42 U.S.C. § 7607(b), and waives the right to challenge the terms of this Order in any action taken to enforce this Order pursuant to Section 113(b) of the CAA, 42 U.S.C. § 7413(b).

VIII. ENFORCEMENT

Failure to comply with this Order may result in a judicial or administrative action for appropriate relief, including civil penalties, as provided in Section 113 of the Act, 42 U.S.C. § 7413. EPA retains full authority to enforce the requirements of the Clean Air Act, 42 U.S.C. §§ 7401-7642, and nothing in this Order shall be construed to limit that authority except as otherwise provided herein.

IX. CERTIFICATION OF REPORTS

Any notice, report, certification, data presentation, or other document submitted by Mirant under or pursuant to this Order, which discusses, describes, demonstrates, or supports any finding or makes any representation concerning Mirant's compliance or non-compliance with any requirement(s) of this Order, shall be certified by a responsible corporate official of Mirant. The term "responsible corporate official" means (a) the Chairman or Chief Operating Officer of Mirant, or (b) Vice President of Operations for PRGS.

23. The certification required by the preceding paragraph of this Order shall be in the following form:

> Except as provided below, I certify that the information contained in or accompanying this (type of submission) is true, accurate, and complete. As to (the/those) portion(s) of this (type of submission) for which I cannot personally verify (its/their) accuracy, I certify under the penalty of law that this (type of submission) and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.
>
> Signature:_____
> Name(print):_____

X. EFFECTIVE DATE AND OPPORTUNITY FOR CONFERENCE

24. By signing this Order, Mirant agrees that it has had an opportunity to confer on the terms of this Order with EPA and thereby waives its opportunity pursuant to Section 113(a)(4) to confer further with EPA concerning the violation(s) alleged in the above Order before the Order takes effect. Therefore, this Order shall be effective upon Mirant's receipt of a copy of the Order signed by the Director of the Air Protection Division, Region 3, or her designee. This Order shall expire one year after execution of the Order, in accordance with Section 113(a)(4) of the CAA, unless it is terminated sooner by EPA.

XI. FAILURE TO PERFORM

25. In the event of an inability or anticipated inability on the part of Mirant to perform any of the actions or work required by this Order in the time and manner required herein, Mirant shall notify EPA orally within twenty-four (24) hours of such event (or, if the event occurs on a Friday

or Saturday, Sunday, or legal holiday, no later than the following business day) and in writing as soon as possible, but in no event more than three (3) days after such event. Such notice shall set forth the reason(s) for, and the expected duration of, the inability to perform; the actions taken and to be taken by Mirant to avoid and mitigate the impact of such inability to perform; and the proposed schedule for completing such actions. Such notification shall not relieve Mirant of any obligation of this Order. Mirant shall take all reasonable actions to prevent and minimize any delay.

XII. BUSINESS CONFIDENTIALITY

26. Mirant is entitled to assert a claim of business confidentiality covering all or part of any requested information, in the manner described in 40 C.F.R. § 2.203(b), unless such information is "emission data" as defined in 40 C.F.R. § 2.301(a)(2). Information subject to a claim of business confidentiality will be made available to the public only in accordance with the procedures set forth in 40 C.F.R. Part 2, Subpart B. Unless a confidentiality claim is asserted at the time requested information is provided, EPA may make this information available to the public without further notice to you.

XIII. COPIES OF ADMINISTRATIVE COMPLIANCE ORDER BY CONSENT

A copy of this Order will be sent to James Sydnor, Virginia Department of Environmental Quality.

Dated: June 1, 2006

Judith Katz, Director
Air Protection Division
U.S. Environmental Protection Agency
Region III

The undersigned represents that he or she is a duly authorized representative of Mirant Potomac River, LLC for the purpose of signing this Order, and that Mirant agrees to the terms of this Order.

Dated: June 1, 2006

Robert Driscoll
Chief Operating Officer

APPENDIX C

Federal Register Notice of Emergency Action and Correspondence with the Council on Environmental Quality

[This page intentionally left blank]

ACTION: Notice of public meeting agenda.

DATE AND TIME: Thursday, February 2, 2006, 10 a.m.–1 p.m.

PLACE: Hyatt Regency (Valley Forge Room), 400 New Jersey Avenue, NW., Washington, DC 20001. (Metro Stop: Union Station).

AGENDA: The Commission will receive the following reports: Title II Requirements Payments Update; and updates on other administrative matters. The Commission will receive presentations on the following topics: Implementation of the EAC Voting System Certification Program.

This meeting will be open to the public.

FOR FURTHER INFORMATION CONTACT: Bryan Whitener. Telephone: (202) 566–3100.

Ray Martinez III,

Vice-Chairman, U.S. Election Assistance Commission.

[FR Doc. 06–607 Filed 1–18–06; 3:32 pm]

BILLING CODE 6820–KF–M

DEPARTMENT OF ENERGY

Emergency Order To Resume Limited Operation at the Potomac River Generating Station, Alexandria, VA, in Response to Electricity Reliability Concerns in Washington, DC

AGENCY: Department of Energy.

ACTION: Notice of emergency action.

SUMMARY: Pursuant to 10 CFR 1021.343, the U.S. Department of Energy is issuing this Notice to document emergency actions that it has taken, and to set forth the steps it intends to take in the future, to comply with the National Environmental Policy Act (NEPA) in the matter described in this Notice.

On August 24, 2005, Mirant Corporation, and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), ceased operations at its Potomac River Generating Station (the ''Plant'') in Alexandria, Virginia, after modeling that it conducted indicated that the Plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act. On the same day, the District of Columbia Public Service Commission (DCPSC) filed with the U.S. Department of Energy (DOE or ''Department''), a petition for an emergency order pursuant to section 202(c) of the Federal Power Act (FPA), asserting that the Plant's closure reduced the reliability of the electrical supply to much of the central business district of the District of Columbia, many federal institutions, the Georgetown area in DC, as well as other portions of Northwest DC, and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Water Treatment Plant (collectively referred to herein as the ''Central DC area''), placing these electrical customers in risk of a blackout.

After an exhaustive review of the facts, and consultation with Federal and state officials responsible for environmental compliance and the private entities responsible for electricity transmission, the Secretary of the Department of Energy on December 20, 2005, issued an emergency order (the ''Order'') directing the Plant's owner, Mirant, to generate electricity at the coal-fired Plant under certain, limited circumstances. The section below on ''Further Information'' includes information on how to obtain paper and electronic copies of the Order.

In emergency situations such as this one, the Council on Environmental Quality (CEQ) Regulations Implementing the Procedural Requirements of NEPA at 40 CFR 1506.11 provide that a federal agency may take an action with significant environmental impacts without observing the provisions of the NEPA regulations associated with preparing an Environmental Impact Statement (EIS). Instead, the agency should consult with CEQ to determine what alternative arrangements the agency will take in lieu of preparing a normal NEPA EIS. DOE has consulted with CEQ about alternative arrangements it will take in this matter and is publishing this notice to inform the public of those arrangements pursuant to DOE's NEPA regulations at 10 CFR 1021.343.

Consistent with its consultation with CEQ, DOE will implement the following alternative arrangements: (1) Prepare a Special Environmental Analysis (SEA) that will examine the potential impacts from issuance of the order, and identify potential mitigation measures; (2) provide opportunities for public involvement by disseminating information related to the environmental effects of Mirant's operations and by accepting public comment on this notice, the compliance plan Mirant submitted to DOE, and the SEA; (3) continue consultations with appropriate agencies with regard to relevant environmental issues; and (4) identify in the SEA any steps that DOE believes can be taken to mitigate the impacts from its Order.

DATES: Comments on this notice and on issues to be addressed in the SEA should be submitted to DOE on or before February 21, 2006.

ADDRESSES: Comments should be addressed to: Lawrence Mansueti, Permitting, Siting, and Analysis Division, Office of Electricity Delivery and Energy Reliability (OE–20), U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585–0119; telephone: 202–586–2588; fax: 202–586–5860; *Lawrence.Mansueti@hq.doe.gov.*

FOR FURTHER INFORMATION CONTACT: For further information on this Notice, to obtain paper copies of the Order and compliance plan, to submit comments on the compliance plan, or for information on the emergency activities related to the Plant, contact Mr. Mansueti at the above address. In addition, all publicly available documents, including the Order and compliance plan, are available on DOE's Web site for this matter at *http://www.electricity.doe.gov/about/dcpsc_docket.cfm* or via hyperlinks from that Web site (referred to herein as the ''Mirant matter Web site''). Copies of the SEA will also be available on the DOE NEPA Web site at *http://www.eh.doe.gov/nepa/.*

For information on the DOE NEPA process, please contact: Carol M. Borgstrom, Director, Office of NEPA Policy and Compliance (EH–42), U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585–0119; telephone: 202–586–4600; fax: 202–586–7031; or leave a toll-free message at: 1–800–472–2756.

SUPPLEMENTARY INFORMATION:

Procedural Background

On August 19, 2005, Mirant submitted to the Virginia Department of Environmental Quality (DEQ) a computerized emissions modeling study Mirant had conducted of its Plant that indicated that emissions from the Plant caused or contributed to significant localized exceedances of the NAAQS. Also on August 19, 2005, DEQ issued a letter to Mirant which requested ''that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shut down of the facility.'' (emphasis in original). On August 24, 2005, Mirant shut down all five of the generating units at the Plant, and on the same day, the District of Columbia Public Service

Commission (DCPSC) filed an Emergency Petition and Complaint with DOE and the Federal Energy Regulatory Commission (FERC) pursuant to the Federal Power Act (FPA). The DCPSC requested the Secretary of Energy to find that an emergency existed under section 202(c) of the FPA and to issue an order directing Mirant to continue operation of the Plant. The basis for the petition was that the shutdown of the Plant ''* * * will have a drastic and potentially immediate effect on the electric reliability in the greater Washington, DC, area and could expose hundreds of thousands of consumers, agencies of the Federal Government and critical federal infrastructure to curtailments of electric service, load shedding and, potentially, blackouts.'' On September 20, 2005, Mirant restarted its unit number one on an 8/8/8 basis—that is, in any given 24-hour period, the unit runs for eight hours at its maximum level of 88 MW, eight hours at its minimum level of 35 MW, and has eight hours when it does not run. DOE has been informed that both the U.S. Environmental Protection Agency (EPA) and DEQ acknowledge that the operation of this unit in this manner does not result in any modeled NAAQS exceedances.

Electricity Reliability

The coal-fired Mirant Plant consists of five generating units, two of which are cycling units that range in output from 35 MW to 88 MW, and three of which are baseload units that range in output from 35 MW to 102 MW. The Plant is one of only three sources of electricity to the Central DC area. The other two sources are two 230,000-volt (230 kV) transmission lines that deliver electricity from other generating sources in the regional electric grid operated by PJM Interconnection (PJM). Although there are other generating units in close physical proximity to the Central DC area, there are no transmission lines that would allow delivery of power from these other units to reach the Central DC area. Under North American Electric Reliability Council (NERC) standards, at a minimum, the power system must carry at least enough contingency reserves of electricity to cover the most severe single contingency. The standards require that an area's system always be operated with sufficient reserves to compensate for the sudden failure of the area's most important single generator or transmission line. Based on the fact that the Central DC area has only three sources of supply, the Plant and the two 230 kV transmission lines, in order to maintain a minimally reliable electric power system, the Plant must be available to run when one of the 230 kV lines is out of service, because if the remaining line failed there would be no other source of electricity to serve the Central DC area load.

The outage of one of these two lines is not merely a theoretical possibility. Since 2000, there have been 34 one-line outages for maintenance, and seven occasions where one of the lines has failed unexpectedly. DOE has been informed that, prior to 2000, there were two occasions when both of the lines failed simultaneously. Moreover, just days before issuance of the Order, PJM informed DOE on December 16, 2005, that on the previous night, ''one of the two circuits critical to providing service to the District tripped. Continued [electric] service to certain load within the District was at that time entirely dependent on the remaining circuit.'' Fortunately, full service to the line that failed was restored by the morning of December 16, 2005. Nonetheless, there can be no assurance that the Central DC area would be so lucky next time. In addition, the Potomac Electric Power Company (PEPCO) informed DOE that it needed to perform maintenance on the lines in January of 2006.

The Order

On December 20, 2005, DOE found that in the circumstances presented, an emergency existed within the meaning of section 202(c) of the FPA because of the reasonable possibility an outage would occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violated applicable reliability standards. PEPCO has applied to the DCPSC to construct two additional 230 kV lines that would supply electricity to the Central DC area and in the same application, proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. Once completed, these lines will likely provide a high level of electricity reliability in the Central DC area, even in the absence of production from the Plant. However, it will likely take 18–24 months to construct the new lines.

Based on this finding, on December 20, 2005, DOE issued an Order requiring Mirant to, among other things, (1) operate the Plant to produce the amount of power (up to its full capabilities) needed to meet demand in the Central DC area during any period in which one or both of the 230kV lines serving the Central DC area is out of service as specified by PJM for the duration of the outage, and (2) keep as many generating units in operation and take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electricity reliability, as feasible, as determined by DOE after consideration of the plan submitted by Mirant pursuant to the Order and after consultation with EPA, without regard to cost, and without causing or significantly contributing to any exceedance of the NAAQS. A blackout in the Central DC area would have drastic impacts on the environment, as well as for the employees and citizens of the Central DC area, affecting hundreds of thousands of residents and workers, as well as public safety and protection facilities, including hospitals, police, and fire facilities. In addition, DOE has been informed that within 24 hours of a blackout in the Central DC area, untreated sewage from the Blue Plains Wastewater Treatment plant would be discharged into the Potomac River.

The time period for DOE's Order extends through October 1, 2006.

Mirant's Compliance Plan

Pursuant to DOE's Order, Mirant submitted a compliance plan (referred to as the Operating Plan by Mirant) on December 30, 2005. The plan outlines a proposed temporary phase, and two options for a proposed intermediate phase, Option A and Option B. All proposals include the use of ''trona'' (sodium sesquicarbonate, a naturally occurring substance similar to baking soda) and/or lower sulfur coal to manage air emissions. On January 4, 2006, DOE authorized Mirant to ''immediately take the necessary steps to implement Option A of the intermediate phase proposed in the implementation plan,'' stating that ''Mirant represents that implementation of this option will produce no NAAQS exceedences.'' DOE will work with EPA to verify the accuracy of that representation. DOE is still in the process of reviewing the other proposals described in Mirant's compliance plan in consultation with EPA.

NEPA Compliance Actions

Pursuant to CEQ regulations at 40 CFR 1506.11, DOE consulted with CEQ on December 20, 2005, December 22, 2005, January 13, 2006, and January 17, 2006, about formulating a plan for alternative arrangements. Under the agreed upon alternative arrangements plan, which will expire October 1, 2006, unless extended, DOE will:

1. *Prepare a Special Environmental Analysis (SEA).* The SEA will examine potential impacts resulting from issuance of the Order, and describe further DOE decisionmaking regarding reasonable future alternatives and potential further mitigation actions DOE may take in this matter. The analysis will present reasonably foreseeable impacts from possible changes in operations of the Plant over the time until two additional transmission lines planned by PEPCO are installed. DOE intends to issue its SEA no later than August 2006 and will make it available to the public on the DOE NEPA and Mirant matter Web sites as well as announce its availability in the **Federal Register**. DOE will consider information contained in the SEA, and public input received on the SEA, in any future decisionmaking in this matter.

2. *Provide Opportunities for Public Involvement.* DOE is currently accepting public comments on the compliance plan that DOE required Mirant to submit under the DOE Order. DOE also invites public comments on this Notice, as well as on issues to be addressed in the SEA. DOE will consider public input in determining appropriate mitigation measures and any additional actions DOE may take as DOE adaptively manages implementation of the Order. DOE will post on the Mirant matter Web site publicly available information (not exempt from disclosure under the Freedom of Information Act) regarding the environmental effects of ongoing or alternative operations of the Plant (*e.g.*, reasonably available ambient air quality data and results of air quality modeling), that the Department receives from Mirant, EPA, and DEQ.

3. *Continue Agency Consultations.* DOE will continue to consult with EPA and DEQ concerning information on emissions, modeling results, potential mitigation measures, and any changes to the operation of the Plant. EPA will act as a ''cooperating agency'' (see 40 CFR 1501.6 and 1508.5) for purposes of providing reasonably available public information regarding the environmental effects of operations of the Plant to be disseminated via DOE's Mirant matter Web site and evaluated in the SEA.

4. *Identify Mitigation.* DOE will identify in its SEA any steps that it believes can be taken to mitigate the impacts from its Order. DOE will continue to track the impacts of its Order and public input and provide for appropriate mitigation where practicable. DOE will publish on its Web sites, as noted above, its discussion of which mitigation measures are adopted for any future decision, and if not, why they are not adopted.

DOE may modify, in consultation with CEQ, the foregoing alternative arrangements as conditions warrant and will notify the public in the **Federal Register** if it does so.

Issued in Washington, DC, on January 18, 2006.

John Spitaleri Shaw,

Assistant Secretary for Environment, Safety and Health.

[FR Doc. 06–570 Filed 1–19–06; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12481–002]

AMG Energy, LLC; Notice of Surrender of Preliminary Permit

January 12, 2006.

Take notice that AMG Energy, LLC, permittee for the proposed Selden Dam Project, has requested that its preliminary permit be terminated. The permit was issued on April 20, 2004, and would have expired on March 31, 2007.[1] The project would have been located on the Black Warrior River in Greene and Hale Counties, Alabama.

The permittee filed the request on December 7, 2005, and the preliminary permit for Project No. 12481 shall remain in effect through the thirtieth day after issuance of this notice unless that day is a Saturday, Sunday, part-day holiday that affects the Commission, or legal holiday as described in section 18 CFR 385.2007, in which case the effective date is the first business day following that day. New applications involving this project site, to the extent provided for under 18 CFR Part 4, may be filed on the next business day.

Magalie R. Salas,

Secretary.

[FR Doc. E6–598 Filed 1–19–06; 8:45 am]

BILLING CODE 6717–01–P

[1] 107 FERC ¶ 62,053.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12485–002]

AMG Energy, LLC; Notice of Surrender of Preliminary Permit

January 12, 2006.

Take notice that AMG Energy, LLC, permittee for the proposed Claiborne Hydroelectric Project, has requested that its preliminary permit be terminated. The permit was issued on June 28, 2004, and would have expired on May 31, 2007.[1] The project would have been located on the Alabama River in Monroe County, Alabama.

The permittee filed the request on December 7, 2005, and the preliminary permit for Project No. 12485 shall remain in effect through the thirtieth day after issuance of this notice unless that day is a Saturday, Sunday, part-day holiday that affects the Commission, or legal holiday as described in section 18 CFR 385.2007, in which case the effective date is the first business day following that day. New applications involving this project site, to the extent provided for under 18 CFR part 4, may be filed on the next business day.

Magalie R. Salas,

Secretary.

[FR Doc. E6–599 Filed 1–19–06; 8:45 am]

BILLING CODE 6717–01–P

[1] 107 FERC ¶ 62,287.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP03–36–015]

Dauphin Island Gathering Partners; Notice of Negotiated Rate

January 13, 2006.

Take notice that on January 9, 2006, Dauphin Island Gathering Partners (Dauphin Island) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, the revised tariff sheets listed below to become effective February 9, 2006.

Twenty-Fourth Revised Sheet No. 9.
Nineteenth Revised Sheet No. 10.
Seventh Revised Sheet No. 359.
Third Revised Sheet No. 427.

Dauphin Island states that these tariff sheets reflect changes to its statement of negotiated rates and nonconforming transportation and reserve commitment agreement tariff sheets.

[This page intentionally left blank]

Department of Energy
Washington, DC 20585

January 18, 2006

Ms. Dinah Bear, General Counsel
Council on Environmental Quality
Executive Office of the President
722 Jackson Place, NW
Washington, DC 20503

Dear Ms. Bear:

The purpose of this letter is to document the Department of Energy's (DOE) consultations with the Council on Environmental Quality (CEQ) regarding compliance with the National Environmental Policy Act (NEPA) analyses and documentation requirements associated with the issuance of an emergency order under section 202(c) of the Federal Power Act (the Order) as a result of the shutdown of the Potomac River Generating Station (the Plant) in Alexandria, Virginia, on August 24, 2005. We thank you and others at CEQ for consulting with DOE on this matter on December 20 and 22, 2005, and January 13 and 17, 2006.

As you are aware, DOE issued its Order on December 20, 2005, requiring the owners of the Plant, Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), to generate electricity in certain limited circumstances. Due to the emergency nature of this matter, DOE issued the Order, despite potentially significant environmental impacts, without observing all of the normal provisions of the CEQ Regulations for Implementing the Procedural Requirements of the National Environmental Policy (NEPA) [40 CFR Parts 1500-1508]. Therefore, DOE is pursuing alternative arrangements to comply with NEPA, as provided in Section 1506.11 of the CEQ regulations. As a result of our discussions with CEQ, we propose the following alternative arrangements, which will expire October 1, 2006, unless extended:

1. Issuance of a *Federal Register* Notice, in accordance with DOE's NEPA regulations at 10 CFR 1021.343. The enclosed draft *Federal Register* Notice documents the emergency action that DOE has taken and actions it intends to pursue in the near term to address the electricity reliability emergency in the District of Columbia. The Notice provides background on Plant operations, outlines the Order DOE issued on December 20, 2005, and acknowledges potential environmental impacts from the Order. The Notice also describes DOE's continuing public involvement and preparation of a Special Environmental Analysis, as discussed below.

2. Prepare a Special Environmental Analysis (SEA). The SEA will examine potential impacts resulting from issuance of the Order, and describe further DOE decisionmaking regarding reasonable future alternatives and potential further

Printed with soy ink on recycled paper

mitigation actions DOE may take in this matter. The analysis will present reasonably foreseeable impacts from possible changes in operations of the Plant over the time until two additional transmission lines planned by Potomac Electric Power Company are installed. DOE intends to issue its SEA no later than August 2006 and will make it available to the public on the NEPA and Mirant matter websites as discussed in the enclosed Notice as well as announce its availability in the *Federal Register*. DOE will consider information contained in the SEA, and public input received on the SEA, in any future decisionmaking in this matter.

3. Provide Opportunities for Public Involvement. DOE is currently accepting public comments on the compliance plan that DOE required Mirant to submit under the DOE Order. DOE also invites public comments on this Notice as well as on issues to be addressed in the SEA. DOE will consider public input in determining appropriate mitigation measures and any additional actions DOE may take as DOE adaptively manages implementation of the Order. DOE will post on DOE's Mirant matter website publicly available information (not exempt from disclosure under the Freedom of Information Act) regarding the environmental effects of ongoing or alternative operations of the Plant (e.g., reasonably available ambient air quality data and results of air quality modeling) that the Department receives from Mirant, the Environmental Protection Agency (EPA), and the Virginia Department of Environmental Quality (DEQ).

4. Continue Agency Consultations. DOE will continue to consult with EPA and DEQ concerning information on emissions, modeling results, potential mitigation measures, and any changes to the operation of the Plant. EPA will act as a "cooperating agency" for purposes of providing reasonably available public information regarding the environmental effects of operations of the Plant to be disseminated via DOE's Mirant matter website and evaluated in the SEA.

5. Identify Mitigation. DOE will identify in its SEA any steps that it believes can be taken to mitigate the impacts from its Order. DOE will continue to track the impacts of its Order and public input and provide for appropriate mitigation where practicable. DOE will publish on its websites as noted above its discussion of which mitigation measures are adopted for any future decision, and if not, why they are not adopted.

We welcome any further suggestions you may have regarding our efforts to comply with NEPA under these emergency circumstances. Thank you for your assistance.

Sincerely,

John Spitaleri Shaw
Assistant Secretary for
Environment, Safety and Health

Enclosure

EXECUTIVE OFFICE OF THE PRESIDENT
COUNCIL ON ENVIRONMENTAL QUALITY
WASHINGTON, D.C. 20503

January 18, 2006

John Spitaleri Shaw
Assistant Secretary for
Environment, Safety and Health
Department of Energy
Washington, DC 20585

Dear Mr. Shaw:

This letter is in response to your January 18, 2006 letter documenting the Department of Energy's (DOE) request, under 40 C.F.R. 1506.11 and 10 CFR 1021.343, that the Council on Environmental Quality (CEQ) provide alternative arrangements for National Environmental Policy Act (NEPA) compliance. Consultation with CEQ is necessary to provide for a NEPA process that addresses the environmental effects of proposals for DOE action needed to maintain a minimally reliable electric power system for the central area of the District of Columbia (DC).

Your letter accurately reflects DOE's consultations with CEQ prior to and following issuance of its December 20, 2005 Order, which requires owners of the Potomac River Generating Station to generate electricity as necessary to address the current limitations of the electricity transmission system that serves central DC. The alternative arrangements proposed in your January 18, 2006 letter are limited to the immediate actions necessary to reduce electricity supply risks to acceptable levels, provide for local involvement and informed decision-making, and otherwise comply with NEPA in a manner appropriate to the nature and scope of the emergency described in the associated Federal Register notice.

Your proposal of alternative arrangements for NEPA compliance is accepted by CEQ. Thank you for your diligent coordination with CEQ. We plan to follow the implementation of these alternative arrangements closely and will remain available for consultation with DOE in this matter at any time.

Sincerely,

Dinah Bear
General Counsel

Recycled Paper

[This page intentionally left blank]

APPENDIX D

Consultation Letters with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service

[This page intentionally left blank]

August 17, 2006

U.S. Fish and Wildlife Service
Threatened and Endangered Species Branch
Chesapeake Bay Office
177 Admiral Cochrane Drive
Annapolis, MD 21401
ATTN: Mary Ratnaswamy

RE: Informal Consultation under Section 7 of the Endangered Species Act (ESA) for Operation of the Potomac River Generating Station in Alexandria, Virginia, Pursuant to DOE Order.

Dear Ms. Ratnaswamy:

This letter is intended to serve as informal consultation under section 7 of the ESA. In this regard, the Department of Energy (DOE) requests that you indicate if there are any additional protected species and habitat (beyond those described below) that should be considered for this ongoing action. If there are not any additional species or habitats and if you agree that the Plant would not impact any species when operating under the DOE Order, we request your concurrence that the operation of the Plant under the terms of the DOE Order would not adversely impact Federally listed or proposed threatened or endangeredspecies or designated or proposed critical habitat and that the consultation requirements of section 7 of the ESA have been satisfied.

Background: On August 24, 2005, Mirant Corporation, and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), ceased operations at its Potomac River Generating Station (the "Plant") in Alexandria, Virginia, after modeling that it conducted indicated that the Plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act.

Also on August 24, 2005, the District of Columbia (D.C.) Public Service Commission filed an *Emergency Petition and Complaint* with DOE pursuant to section 202(c) of the Federal Power Act.

On December 20, 2005, after an exhaustive review of the facts and consultation with Federal and state officials responsible for environmental compliance and the private entities responsible for operation of the region's electrical grid, the Secretary of Energy issued an emergency order (the "Order") directing Mirant to generate electricity at the coal-fired Plant under certain, limited circumstances. On June 1, 2006, Mirant entered into an Administrative Consent Order (ACO) with the Environmental Protection Agency (EPA) regarding the operation of the Plant. On June 2, 2006, DOE instructed Mirant to comply with the ACO and operate as required under it.

After consultations with the Council on Environmental Quality (CEQ), DOE's Office of Electricity Delivery and Energy Reliability decided to prepare a special environmental analysis (SEA) under the emergencies provision of CEQ's National Environmental Policy Act (NEPA) Implementing Regulations (40 CFR 1506.11) and the emergency circumstances provision of DOE's own NEPA implementing regulations [10 CFR 1021.343(a)]. The SEA will document the assessment of the impacts associated with the emergency activities under DOE Order 202-05-03. The time period for DOE's Order extends to October 1, 2006; however, the SEA also addresses the 15-month period from October 1, 2006, through December 31, 2007, at which time new transmission lines are expected to be available to provide a high level of electric reliability to customers in the Central D.C. area, even in the absence of production from the Plant.

The Plant: The Potomac River Generating Station began operation in 1949 and is capable of producing 482 megawatts of electric power. The Plant site encompasses 28 acres (11 has) near D.C. and Reagan National Airport on the western bank of the Potomac River (Figure 1). Most of the property is used for power generation, coal storage, office buildings, and parking areas. The site was relatively remote when the power plant was built, but Alexandria has grown up around it. The Plant is beneath the flight path of Reagan National Airport.

EPA issued a National Pollutant Discharge Elimination System (NPDES) permit to the Plant on April 20, 2000, authorizing discharges into the Potomac River. The Virginia Department of Environmental Quality approved a Stationary Source Permit to Operate on September 18, 2000, and a Phase II Acid Rain Permit on February 23, 2003.

Coal combustion ash from the Plant is sent to the Brandywine Fly Ash Facility, which is located in southeastern Prince George's County, Maryland (Figure 2). Water from this landfill discharges into the upper reaches of Mataponi Creek.

Action at the Plant under DOE's Order: The DOE Order resulted in no new disturbances from construction at the Plant site. The provisions of DOE's Order and subsequent instructions to Mirant have, however, caused changes in the level of operation at the Plant. These changes have reduced the operating level of the Plant to below that at which it was historically operating before August 24, 2005, but increased the operating level above that at which it was operating between August 24 and December 20, 2005. To reduce sulfur dioxide (SO_2) emissions, Mirant has been using a compound known as "trona" (sodium sesquicarbonate, a naturally occurring substance similar to baking soda) and/or lower sulfur coal. Thus, even if the Plant were operating at the same level as before August 24, 2005, its emissions of SO_2 would be lower.

Threatened and Endangered (T&E) Species Impacts: Because the Plant site is heavily industrialized and surrounded by development in the City of Alexandria, no Federally listed or proposed threatened or endangered species are known or likely to occur on the Plant site. Also, there is no known designated or proposed critical habitat in the area of the action.

Of the permits issued for the Plant or landfill, only the NPDES permit for the Plant mentions T&E species. That permit states that two species listed by the U.S. Fish and Wildlife Service (FWS) under the ESA occur or may occur at locations near the Plant. These are the endangered Hay's Spring amphipod *(Stygobromus hayi)* and the threatened bald eagle *(Haliaeetus leucocephalus).*

The Plant's NPDES permit states, "The FWS and NMFS indicate that at the present time [i.e., April 20, 2000] there is no evidence that the ongoing wastewater discharges covered by this permit are adversely affecting these Federally listed species." Furthermore, "(w)astewater discharges, construction, or any other activity that adversely affects a Federally listed endangered or threatened species are [sic] not authorized under the terms of this permit."

The Hay's Spring amphipod occurs only in a small area in Rock Creek in D.C. The bald eagle is unlikely to occur near the Plant as the area around it is developed and provides no suitable habitat. There has been no known impact to these species due to the Plant's operation prior to the DOE Order. Thus, since there has been no impact to Federally listed threatened or endangered species when the Plant was operating at the higher historical level before August 24, 2005, adverse impacts to such species from the lower level of operation at the Plant under DOE's Order would not be expected.

Since the DOE Order is scheduled to expire on October 1, 2006, receipt of your reply and/or concurrence before that date will allow DOE to consider your comments in determining what, if any, future actions to take in this matter.

If you need additional information or wish to discuss this matter further, please contact me at (202) 586-5935.

Sincerely,

Anthony J. Como
Director, Permitting and Siting
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy

Enclosures (2)

[This page intentionally left blank]

August 17, 2006

Northeast Regional Office
National Marine Fisheries Service
Protected Resource Division
One Blackburn Drive
Gloucester, MA 01930
Attn: Julie Crocker

RE: **Informal Consultation under Section 7 of the Endangered Species Act (ESA) for Operation of the Potomac River Generating Station in Alexandria, Virginia, Pursuant to DOE Order.**

Dear Ms. Crocker:

This letter is intended to serve as informal consultation under section 7 of the ESA. In this regard, the Department of Energy (DOE) requests that you indicate if there are any additional protected species and habitat (beyond those described below) that should be considered for this ongoing action. If there are not any additional species or habitats and if you agree that the Plant would not impact any species when operating under the DOE Order, we request your concurrence that the operation of the Plant under the terms of the DOE Order would not adversely impact Federally listed or proposed threatened or endangered species or designated or proposed critical habitat and that the consultation requirements of section 7 of the ESA have been satisfied.

Background: On August 24, 2005, Mirant Corporation, and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), ceased operations at its Potomac River Generating Station (the "Plant") in Alexandria, Virginia, after modeling that it conducted indicated that the Plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS) of the Clean Air Act.

Also on August 24, 2005, the District of Columbia (D.C.) Public Service Commission filed an *Emergency Petition and Complaint* with DOE pursuant to section 202(c) of the Federal Power Act.

On December 20, 2005, after an exhaustive review of the facts and consultation with Federal and state officials responsible for environmental compliance and the private entities responsible for operation of the region's electrical grid, the Secretary of Energy issued an emergency order (the "Order") directing Mirant to generate electricity at the coal-fired Plant under certain, limited circumstances. On June 1, 2006, Mirant entered into an Administrative Consent Order (ACO) with the Environmental Protection Agency (EPA) regarding the operation of the Plant. On June 2, 2006, DOE instructed Mirant to comply with the ACO and operate as required under it.

After consultations with the Council on Environmental Quality (CEQ), DOE's Office of Electricity Delivery and Energy Reliability decided to prepare a special environmental analysis (SEA) under the emergencies provision of CEQ's National Environmental Policy Act (NEPA) Implementing Regulations (40 CFR 1506.11) and the emergency circumstances provision of DOE's own NEPA implementing regulations [10 CFR 1021.343(a)]. The SEA will document the assessment of the impacts associated with the emergency activities under DOE Order 202-05-03. The time period for DOE's Order extends to October 1, 2006; however, the SEA also addresses the 15-month period from October 1, 2006, through December 31, 2007, at which time new transmission lines are expected to be available to provide a high level of electric reliability to customers in the Central D.C. area, even in the absence of production from the Plant.

The Plant: The Potomac River Generating Station began operation in 1949 and is capable of producing 482 megawatts of electric power. The Plant site encompasses 28 acres (11 ha) near the D.C. and Reagan National Airport on the western bank of the Potomac River (Figure 1). Most of the property is used for power generation, coal storage, office buildings, and parking areas. The site was relatively remote when the power plant was built, but Alexandria has grown up around it. The Plant is beneath the flight path of Reagan National Airport.

EPA issued a National Pollutant Discharge Elimination System (NPDES) permit to the Plant on April 20, 2000, authorizing discharges into the Potomac River. The Virginia Department of Environmental Quality approved a Stationary Source Permit to Operate on September 18, 2000, and a Phase II Acid Rain Permit on February 23, 2003.

Coal combustion ash from the Plant is sent to the Brandywine Fly Ash Facility, which is located in southeastern Prince George's County, Maryland (Figure 2). Water from this landfill discharges into the upper reaches of Mataponi Creek.

Action at the Plant under DOE's Order: The DOE Order resulted in no new disturbances from construction at the Plant site. The provisions of DOE's Order and subsequent instructions have, however, caused changes in the level of operation at the Plant. These changes have reduced the operating level of the Plant to below that at which it was historically operating before August 24, 2005, but increased the operating level above that at which it was operating between August 24 and December 20, 2005. To reduce sulfur dioxide (SO_2) emissions, Mirant has been using a compound known as "trona" (sodium sesquicarbonate, a naturally occurring substance similar to baking soda) and/or lower sulfur coal. Thus, even if the Plant were operating at the same level as before August 24, 2005, its emissions of SO_2 would be lower.

Threatened and Endangered (T&E) Species Impacts: Because the Plant site is heavily industrialized and surrounded by development in the City of Alexandria, no Federally listed or proposed threatened or endangered species are known or likely to occur on the Plant site. Also, there is no known designated or proposed critical habitat in the area of the action.

Of the permits issued for the Plant or landfill, only the NPDES permit for the Plant mentions T&E species. That permit states that one species listed by the National Marine Fisheries Service (NMFS) under the ESA, the endangered shortnose sturgeon *(Acipenser brevirostrum)*, occurs or may occur at locations near the Plant.

The Plant's NPDES permit states, "The FWS and NMFS indicate that at the present time [i.e., April 20, 2000] there is no evidence that the ongoing wastewater discharges covered by this permit are adversely affecting these Federally listed species." Furthermore, "(w)astewater discharges, construction, or any other activity that adversely affects a Federally listed endangered or threatened species are [sic] not authorized under the terms of this permit."

The Shortnose Sturgeon Recovery Plan reports that one shortnose sturgeon was captured in 1996 at the mouth of Potomac Creek off the Potomac River downstream from the Plant. However, there are no other recent reports of it occurring in the Potomac River; therefore, there has been no known impact to this species due to the Plant's operation prior to the DOE Order. Since there has been no known impact to Federally listed threatened or endangered species when the Plant was operating at the higher historical level before August 24, 2005, adverse impacts to such species from the lower level of operation at the Plant under DOE's Order would not be expected.

Since the DOE Order is scheduled to expire on October 1, 2006, receipt of your reply and/or concurrence before that date will allow DOE to consider your comments in determining what, if any, future actions to take in this matter.

If you need additional information or wish to discuss this matter further, please contact me at (202) 586-5935.

Sincerely,

Anthony J. Como
Director, Permitting and Siting
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy

Enclosures (2)

[This page intentionally left blank]

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
NORTHEAST REGION
One Blackburn Drive
Gloucester, MA 01930-2298

OCT - 3 2006

Anthony J. Como, Director
Permitting and Siting
Office of Electricity Delivery and Energy Reliability
US Department of Energy
Washington, DC 20585

Dear Mr. Como,

This is in response to your letter dated August 17, 2006 requesting consultation pursuant to Section 7 of the Endangered Species Act (ESA) of 1973, as amended, regarding the operation of Mirant's Potomac River Generating Station in Alexandria, Virginia.

The Potomac River Generating Station is a coal fired plant located on the western bank of the Potomac River. The Plant began operation in 1949. On August 24, 2005, Mirant ceased operations at its Plant after modeling indicated that the Plant's operations were causing exceedences of the National Ambient Air Quality Standards of the Clean Air Act. On December 20, 2005, the Secretary of Energy issued an emergency order directing Mirant to generate electricity at the Plant under certain circumstances. On June 1, 2006, Mirant entered into an Administrative Consent Order (ACO) with the US Environmental Protection Agency (EPA) regarding the operation of the Plant. The DOE requires the Plant to operate at lower levels and to reduce sulfur dioxide emissions by using a compound known as "trona" (sodium sesquicarbonate) and/or lower sulfur coal. On June 2, 2006, the Department of Energy (DOE) instructed Mirant to comply with the ACO and operate as required under it. Operation of the Plant is necessary to ensure an uninterrupted supply of electricity to the District of Columbia. DOE has indicated that its order to comply with the ACO is scheduled to expire on October 1, 2006. The operation of the Plant from October 1, 2006 through summer 2007 under the terms of the DOE Order is the subject of this consultation. The DOE has made the determination that the operation of the Plant under the Order is not likely to adversely affect any species listed under the jurisdiction of NOAA's National Marine Fisheries Service (NMFS) and has requested that NMFS concur with this determination.

As noted in your letter, the only species listed under the jurisdiction of NMFS that may be present in the vicinity of the proposed project is the endangered shortnose sturgeon (*Acipenser brevirostrum).* During the 1996-2005 time period, the incidental capture of seventy-two different shortnose sturgeon in the Chesapeake Bay and its tributaries had been reported via the US Fish and Wildlife Service Atlantic sturgeon reward program. This number includes six shortnose sturgeon captured incidentally in fishing gear in the Potomac River. Additionally, researchers conducting a survey for shortnose sturgeon in the river captured one mature egg bearing female

in September 2005 and an additional mature egg bearing female in the same location in March 2006. Both fish have been outfitted with sonic tags and are being actively tracked by researchers. The female caught in September overwintered in the Potomac River near Mattawoman Creek. One of the females was documented at the presumed spawning grounds near Little Falls in the spring of 2006. The occurrence of pre-spawning females in the Potomac River suggests that a spawning population of shortnose sturgeon continues to exist in this river system. The Plant is located approximately 24 miles upstream of the suspected overwintering area. Population dynamics of shortnose sturgeon in the Potomac River have not been documented. However, based on patterns in other river systems, shortnose sturgeon likely migrate past the Plant while moving to and from the spawning grounds near Little Falls in the spring (March – June). It is unknown if shortnose sturgeon would occur in this region of the river during other times of the year. If appropriate forage items are present, shortnose sturgeon could also occur in the area in the summer and fall while foraging.

The continuation of operations from October 1, 2006 through summer 2007, would not result in any new construction or in-water disturbances at the plant. The only aspect of the Plant's continued operation that has the potential to impact shortnose sturgeon is the discharge of waste water from the Plant to the Potomac River. These discharges are authorized under a NPDES permit issued by the EPA. NMFS has previously consulted with the EPA on the NPDES permit for the Plant and determined that the discharges are not likely to adversely affect shortnose sturgeon. While the past operation of the plant has resulted in air quality impairments, there is no information available that indicates that the operation of the plant has had an adverse effect on water quality in the Potomac River. No other impacts from the operation of the Plant under the DOE order are likely. As such, NMFS concurs with DOE's determination that the continued operation of the Plant through summer 2007 is not likely to adversely affect any species listed under NMFS jurisdiction. Therefore, no further consultation pursuant to section 7 of the ESA is required. Should project plans change or new information become available that changes the basis for this determination, or a new species be listed or critical habitat designated, consultation should be reinitiated. Should you have any questions about this correspondence please contact Julie Crocker at (978) 281-9300 ext. 6530.

Sincerely,

Patricia A. Kurkul
Regional Administrator

Cc: Scida, F/NER3
Nichols, F/NER4
Williams, GCNE

File Code: Sec 7 DOE Mirant Potomac Generating Station
PCTS I/NER/2006/04102

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Chesapeake Bay Field Office
177 Admiral Cochrane Drive
Annapolis, MD 21401
410/573-4575

November 20, 2006

RE: Informal Consultation under Section 7 of the Endangered Species Act (ESA) for Operation of the Potomac River generating Station in Alexandria, Va.

Dear Mr. Como,

This responds to your letter, received November 20, 2006, requesting information on the presence of species which are federally listed or proposed for listing as endangered or threatened in the above referenced project area. We have reviewed the information you enclosed and are providing comments in accordance with section 7 of the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*).

Except for occasional transient individuals, no proposed or federally listed endangered or threatened species are known to exist within the project impact area. Therefore, no Biological Assessment or further section 7 consultation with the U.S. Fish and Wildlife Service is required. Should project plans change, or should additional information on the distribution of listed or proposed species become available, this determination may be reconsidered.

This response relates only to federally protected threatened or endangered species under our jurisdiction. Limited information is currently available regarding the distribution of other rare species in the District of Columbia. However, the Nature Conservancy and National Park Service (NPS) have initiated an inventory of rare species within the District. For further information on such rare species, you should contact Mary Pfaffko of the National Park Service at (202)-535-1739.

An additional concern of the Service is wetlands protection. Federal and state partners of the Chesapeake Bay Program have adopted an interim goal of no overall net loss of the Basin's remaining wetlands, and the long term goal of increasing the quality and quantity of the Basin's wetlands resource base. Because of this policy and the functions and values wetlands perform, the Service recommends avoiding wetland impacts. All wetlands within the project area should be identified, and if alterations of wetlands is proposed, the U.S. Army Corps of Engineers, Baltimore District, should be contacted for permit requirements. They can be reached at (410) 962-3670.

We appreciate the opportunity to provide information relative to fish and wildlife issues, and

thank you for your interests in these resources. If you have any questions or need further assistance, please contact Devin Ray at (410) 573-4531.

Sincerely,

Mary Ratnaswamy

Mary J. Ratnaswamy, Ph.D.
Program Supervisor, Threatened and Endangered Species

APPENDIX E

Organizational Conflict of Interest Statement

[This page intentionally left blank]

NEPA DISCLOSURE STATEMENT FOR PREPARATION OF A
SPECIAL ENVIRONMENTAL ANALYSIS FOR ACTIONS TAKEN UNDER DOE ORDER 202-05-3 REGARDING OPERATION OF THE POTOMAC RIVER GENERATING STATION IN ALEXANDRIA, VIRGINIA

CEQ Regulations at 40 CFR 1506.5(c), which have been adopted by the DOE (10 CFR 1021), require contractors who will prepare an environmental impact statement to execute a disclosure specifying that they have no financial or other interest in the outcome of the project. The term "financial interest or other interest in the outcome of the project" for purposes of this disclosure is defined in the March 23, 1981, guidance "Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations," 46 FR 18026-18038 at Question 17a and b.

"Financial or other interest in the outcome of the project" includes "any financial benefit such as a promise of future construction or design work in the project, as well as indirect benefits the contractor is aware of (e.g., if the project would aid proposals sponsored by the firm's other clients)." 46 FR 18026-10838 at 10831.

In accordance with these requirements, the offeror and any proposed subcontractors hereby certify as follows: [check either (a) or (b) to assure consideration of your proposal].

(a) __X__ Offeror and any proposed subcontractor have no financial or other interest in the outcome of the project.

(b) _____ Offeror and any proposed subcontractor have the following financial or other interest in the outcome of the project and hereby agree to divest themselves of such interest prior to award of this contract.

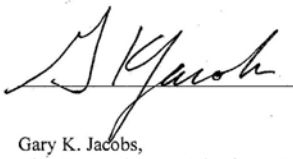
Financial or Other Interests

1.

2.

3.

Certified by:



Signature

Gary K. Jacobs,
Director, Environmental Sciences Division
Printed Name and Title

Oak Ridge National Laboratory,
Managed for the U.S. Department of Energy
by UT-Battelle, LLC
Company

11-1-06
Date

[This page intentionally left blank]

APPENDIX F

Glossary

[This page intentionally left blank]

GLOSSARY

Anadromous - species that spend their adult lives in saltwater and spawn in freshwater.

Ash - the mineral content of a product remaining after complete combustion.

Baseload - generating units that produce power at a steady rate for extended periods.

Biochemical oxygen demand - a standard quantitative measure of water pollution. It is the amount of oxygen consumed in the biological oxidation (by bacteria or other microorganisms) of organic material in a unit volume of waste water, as measured over a five-day period. Biochemical oxygen demand sometimes is divided into two components: carbonaceous oxygen demand and nitrogenous oxygen demand. Carbonaceous biochemical oxygen demand is the result of the breakdown of organic molecules such as cellulose and sugars, while nitrogenous oxygen demand is the result of the breakdown of proteins.

Biocide - a substance (e.g., chlorine) that is toxic or lethal to many organisms and is used to treat water.

Blowdown - the portion of steam or water removed from a boiler at regular intervals to prevent excessive accumulation of dissolved and suspended materials.

Bottom ash - combustion residue composed of large particles that settle to the bottom of a combustor from where they can be physically removed.

Calcining - the effects of heating a substance to a high temperature (below the melting or fusing point) at which point loss of moisture, reduction or oxidation, or the decomposition of carbonates and other compounds occurs.

Candidate species - plants and animals native to the United States for which the Fish and Wildlife Service or the National Marine Fisheries Service has sufficient information on biological vulnerability and threats to justify proposing to add them to the threatened and endangered species list, but cannot do so immediately because other species have a higher priority for listing. The Services determine the relative listing priority of candidate taxa in accordance with general listing priority guidelines published in the *Federal Register*. (See endangered species and threatened species.)

Cooling water - water that is heated as a result of being used to cool steam and condense it to water.

Cyanobacteria - blue-green algae.

Diadromous - fish spending part of their lives in both fresh and salt water.

Downwash (building) - the downward movement of an elevated plume toward the area of low pressure created on the lee side of a structure in the wake around which the air flows.

Electrostatic precipitator - a device that removes particles from a stream of exhaust gas. It imparts an electrical charge to the particles, which causes them to adhere to metal plates that can be rapped to cause the particles to fall into a hopper for disposal.

Endangered species - plants or animals that are in danger of extinction through all or a significant portion of their ranges and that have been listed as endangered by the Fish and Wildlife Service or the National Marine Fisheries Service following the procedures outlined in the Endangered Species Act and its implementing regulations (50 CFR 424). (See threatened species.) The lists of endangered species can be found in 50 CFR 17.11 (wildlife), 50 CFR 17.12 (plants), and 50 CFR 222.23(a) (marine organisms). The state of Virginia also lists species as endangered under its Endangered Species Act.

Entrainment - incorporation of any life stage of fish and shellfish with water flow entering and passing through a cooling water intake structure and into an industrial, municipal or electric utility power plant cooling water system.

Estuary - region of interaction between rivers and near-shore ocean waters, where tidal action and river flow mix fresh and salt water. Such areas include bays, mouths of rivers, salt marshes, and lagoons. These brackish water ecosystems shelter and feed marine life, birds, and wildlife. (See wetlands.)

Fall line - the boundary zone where the upland piedmont region meets the coastal plain. Waterfalls and rapids occur where rivers and streams cross the fall line.

Finfish - a fish with fins (which is most fish), in contrast to shellfish, crayfish, and jellyfish (which are not fish).

Fly ash - combustion residue composed of fine particles (e.g., soot) that are entrained with the draft leaving the combustor.

Fresh water - water with a low concentration of salts (typically less than 1,000 parts per million of dissolved solids).

Hazardous waste - a category of waste regulated under the Resource Conservation and Recovery Act (RCRA). To be considered hazardous, a waste must be a solid waste under RCRA and must exhibit at least one of four characteristics described in 40 CFR 261.20 through 40 CFR 261.24 (i.e., ignitability, corrosivity, reactivity, or toxicity) or be specifically listed by the Environmental Protection Agency in 40 CFR 261.31 through 40 CFR 261.33.

Impingement - the entrapment of any life stage of fish and shellfish on the outer part of an intake structure or against a screening device during intake water withdrawal.

Leachate - solution or product obtained by leaching, in which a substance is dissolved by the action of a percolating liquid.

Load following - power generating units that are capable of changing power levels quickly as demand rises or falls. They are also known as cycling units.

pH - a measure of the relative acidity or alkalinity of a solution, expressed on a scale from 0 to 14, with the neutral point at 7. Acid solutions have pH values lower than 7, and basic (i.e., alkaline) solutions have pH values higher than 7.

Plume (atmospheric) - a visible or measurable, elongated pattern of emissions spreading downwind from a source through the atmosphere.

Pozzolanic - material that when mixed with water "sets," like cement.

Riparian - areas adjacent to rivers and streams with a differing density, diversity, and productivity of plant and animal species relative to nearby uplands.

Saline - describes water with high concentrations of salts (typically more than 10,000 parts per million dissolved solids), making it unsuitable for use.

Stratosphere - the portion of the atmosphere 10 to 25 mi (16 to 40 km) above the earth's surface.

Threatened species - any plants or animals that are likely to become endangered species within the foreseeable future throughout all or a significant portion of their ranges and which have been listed as threatened by the Fish and Wildlife Service or the National Marine Fisheries Service following the procedures set out in the Endangered Species Act and its implementing regulations (50 CFR 424). (See endangered species.) The lists of threatened species can be found at 50 CFR 17.11 (wildlife), 17.12 (plants), and 227.4 (marine organisms). The state of Virginia also lists species as threatened under its Endangered Species Act.

Tidal river - a river segment with fresh water (salinity less than 500 mg/L) and a net seaward flow direction throughout the water column.

Transmission (electric) - movement of electrical power from the source where it is produced to end users.

Trona - a naturally occurring chemical compound, sodium sesquicarbonate, similar to baking soda.

Troposphere - the layer of the atmosphere closest to the earth's surface.

Watershed - the region draining into a river, river system, or other body of water.

Wetlands - areas that are inundated or saturated by surface water or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions, including swamps, marshes, bogs, and similar areas.

Wind rose - a graph in which the frequency of wind blowing from each direction is plotted as a bar that extends from the center of the diagram. Wind speeds are denoted by bar widths and shading; the frequency of wind speed within each wind direction is depicted according to the length of that section of the bar.

Department of Energy
Washington, DC 20585

October 1, 2021

Enclosed is the final special environmental analysis (DOE/SEA-05) prepared by ICF, Incorporated (ICF) under direction of the Department of Energy (DOE) pursuant to the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4331 et seq., and DOE's implementing regulations, 10 CFR 1021.343(a).

On February 14, 2021, DOE issued an emergency order pursuant to section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the DOE Organization Act, 42 U.S.C. § 7151(b), DOE Order No. 2020-21-1, to the Electric Reliability Council of Texas (ERCOT) authorizing specific electric generating units located within the ERCOT area to operate at their maximum generation output levels under limited circumstances due to extreme weather conditions and to preserve the reliability of bulk electric power system (Order).

DOE issued the Order after determining that the emergency situation underlying ERCOT's request demanded immediate action consistent with DOE's NEPA regulations (10 CFR 1021.343(a)). As described in DOE's notice of emergency action (86 FR 18046; April 7, 2021), DOE reviewed the final data report received from ERCOT on March 31, 2021, and determined that a special environmental analysis would be the appropriate level of NEPA review. DOE has prepared special environmental analyses in other emergency situations that required immediate action. (See https://www.energy.gov/nepa/special-environmental-analyses). This special environmental analysis examines potential impacts resulting from issuance of the Order on air quality and environmental justice. DOE has independently reviewed the analysis provided by ICF and agrees with its conclusions. No further analysis will be conducted.

U.S. Department of Energy, Office of Electricity

Air Quality and Environmental Justice Analysis Memorandum, July 21, 2021

Introduction

During 5 days in February 2021 (February 15–19), the Electric Reliability Council of Texas (ERCOT) requested the Department of Energy (DOE) to authorize the emergency use of power generation under Section 202(c) of the Federal Power Act. This resulted in air emissions at times exceeding their permitted emissions levels for 28 power units located in East Texas, with most power units (20) located in Harris County. At the request of the DOE Office of Electricity (OE), ICF has examined whether these additional emissions from these power units covered by the Section 202(c) authorization may have led to an exceedance of the National Ambient Air Quality Standards (NAAQS). Further, ICF conducted an environmental justice analysis of the communities potentially affected by any additional emissions during this 5-day period.

We determined at the outset that for one power unit, ERCOT was unable to obtain any information on its air emissions. Therefore, our analyses included 27 units. Although the ERCOT Section 202(c) permit covered 27 power units, only 14 of the 27 power units were at unique locations.

1 Air Quality Analysis Approach

To assess whether emissions from the power units could potentially contribute to a NAAQS violation, ICF gathered the air quality monitoring data for stations in East Texas. The Texas Commission on Environmental Quality (TCEQ) maintains an extensive network of air monitoring stations throughout the state.[1] This hourly air monitoring and meteorological data, resultant wind speed and direction, outdoor temperature, standard deviation in wind direction, and solar radiation were downloaded from TCEQ. In addition, ERCOT provided the locations for each power generating unit. Using this collected data, ICF determined if any exceedances occurred during the emergency period (February 15–19, 2021) for air pollutants having short-term ambient air quality standards. This included 1- and 8-hour CO, 1-hour NO_2, 1-hour SO_2, and 24-hour PM^2 standards. No assessment was made for mercury or CO_2 emissions.

ERCOT provided DOE with hourly air emission rates for each unit above its permitted levels, along with the location of each power unit. This information was used to pair air quality monitoring stations with power units. We examined pairings using proximate radial distances of 10 km and 15 km. To determine if an air monitoring station was downwind of the power unit, we used each hour's wind direction to determine if the air monitoring station aligned in a downwind direction within a ±20-degree window.

To further strengthen conclusions, we compared the 5-day average temperature with historical average February temperatures using climatological data from Houston International Airport as an overall representative site. Lower than average temperatures are favorable for increased

[1] https://www.tceq.texas.gov/cgi-bin/compliance/monops/select_month.pl

[2] Although PM_{10} is the reported emission rate, we used the $PM_{2.5}$ standard, as nearly all (>97 percent by mass) of the power plant emissions have a mean mass diameter of less than 2.5 microns.

buoyancy from the exhaust stack, which means the plume will rise higher, favoring lower ground-level air concentrations. A similar analysis was performed for wind speeds but using the Houston Aldine site (EPA AIRS ID 48_201_0024). Here, higher wind speeds led to increased ventilation, which decreases residence time of air pollutants, leading to lower air pollutant concentrations.

Lastly, we discuss the concept of mixing height. The *mixing height* (or depth) is defined as the height above the Earth's surface through which vertical mixing occurs. The concept of a mixing layer is well-founded on theoretical principles. The mixing height acts as a lid on air pollutants, tending to prevent further vertical mixing of emissions higher into the atmosphere. Thus, we calculated the mixing heights during the 5-day emergency period and compared them to the average February mixing heights based on the Holzworth method (U.S. Environmental Protection Agency, 1972). Mixing heights can be determined from twice daily upper-air soundings performed at 6 a.m. and 6 p.m. The nearest upper-air station to Harris County is Lake Charles, Louisiana.

Review of ERCOT Emission Rates Against Total Emissions Rates During the Emergency Use Period

We reviewed the hourly emission rate data provided by ERCOT for each power unit. The dataset is intended to report the incremental emissions for each hour that exceeded the power units' maximum permitted emission rates. To compare these incremental emissions against the total emissions from each power unit, we downloaded the Continuous Emission Monitoring System (CEMS) from EPA's Air Markets Program Data (ampd.epa.gov/ampd). CEMS data reports the total emissions for each power unit on an hour-by-hour basis either as directly measured or as calculated from other measured parameters. The ERCOT data reported hourly emissions for SO_2, NO_X, CO, PM_{10}, and CO_2; however, CEMS does not report emissions for CO and PM_{10}, so the only pollutants that can be cross-referenced between the two datasets are SO_2, NO_X, and CO_2. However, SO_2 and CO_2 are rarely reported in the ERCOT-supplied data, likely because SO_2 emission rates are well below permitted levels even during the emergency period, and CO_2 emission rates are likely not specified in operating permit levels.

Because the ERCOT emission rates are in, we expected that in most cases the ERCOT incremental increase would only be a small fraction of the total CEMS rates and that the ERCOT rates could never be greater than CEMS rates because CEMS emissions are the total emissions from the power units. To see if our understanding is consistent with the reported data, we made a graphical presentation between the NO_X incremental emission rate versus the CEMS emissions rate for each hour in which ERCOT reported an emission rate over the 5-day emergency period.

1.1 Findings – Potential for NAAQS Exceedances

We discuss a series of analyses undertaken using available air quality and meteorological data to present a weight-of-evidence approach in trying to answer the principal question—*Could the power units' excess air emissions during this emergency period have caused an exceedance of the NAAQS?*

No one analysis can definitively answer this question, so we performed a series of analyses to provide a more defensible and robust conclusion and instill greater confidence in the answer.

1.1.1 Air Quality Monitoring Stations

A review of air quality monitoring stations in all air quality modeling regions in East Texas showed no violations of the NAAQS during the emergency period. However, many of the air quality monitoring stations failed to operate during the emergency period, presumably because of power outages. Tables 1a and 1b below show the daily percentage of missing air quality data during the emergency period for power units and air quality stations that we could pair using a 10-m radius. Only 14 of the 27 power units had unique locations, and of the 14 locations, only 10 had an air quality station within 10 km. The pollutant most widely monitored, as well as the pollutant most widely reported as having emissions exceeding permit levels, is NO_X. Of the 14 locations, seven had NO_2 monitors.[3] However, as highlighted in light blue and indicated with an asterisk (*), about half have missing data (likely as a result of power outages), particularly on the first 3 days of the emergency period. Other air pollutants have less air monitoring coverage but also show considerable missing data, particularly during the first 3 days of the emergency period.

The power unit codes shown in the rest of this report are defined in Appendix 1.

[3] Although the emitted pollutant is NO_X, the air quality standard is for NO_2. Typically, about 10 percent of the in-stack NO_X is in the form of NO_2, and the rest is emitted as NO. However, NO is converted to NO_2 in the atmosphere with a reaction rate on the order of minutes to hours, depending on available ozone and atmospheric mixing.

Table 1a. Ambient Air Quality Monitoring Stations (CO and NO_2) Within 10 km of the Power Generation Units

Power Unit Name	Pollutants of Interest Monitored				Data Coverage by Day CO					Data Coverage by Day NO_2				
	CO	NO_2	$PM_{2.5}$	SO_2	2/15	2/16	2/17	2/18	2/19	2/15	2/16	2/17	2/18	2/19
BOSQUE_CC1														
DDPEC_CC1	X	X	X	X	100%	21%*	0%*	50%	100%	100%	21%*	75%	100%	100%
FREC_CC2				X										
TXCTY_CC1				X										
CHAMON_CTG_0101		X								75%	0%*	17%*	100%	100%
CALHOUN_UNIT1														
THW_THWGT32		X								100%	92%	38%*	100%	100%
WAP4_WAP4														
GBY_GBYGT74		X	X							100%	96%	50%	100%	100%
PHR_CLCWA_5UNITS		X								8%*	88%	42%*	100%	96%
LH_LYN_30UNITS		X								75%	0%*	17%*	100%	100%
DSN_NEWP_10UNITS														
SOE_SEWP_10UNITS	X	X	X	X	100%	21%*	0%*	50%	100%	100%	21%*	75%	100%	100%
FEGC_UNIT1				X										

See Appendix 1 for definition of the unit codes.

Table 1b. Ambient Air Quality Monitoring Stations (PM25, SO_2) Within 10 km of the Power Generation Units

Power Unit Name	Pollutants of Interest Monitored				Data Coverage by Day $PM_{2.5}$					Data Coverage by Day SO_2				
	CO	NO_2	$PM_{2.5}$	SO_2	2/15	2/16	2/17	2/18	2/19	2/15	2/16	2/17	2/18	2/19
BOSQUE_CC1														
DDPEC_CC1	X	X	X	X	100%	17%*	71%	100%	83%	100%	21%*	67%	100%	100%
FREC_CC2				X						0%*	0%*	0%*	46%*	100%
TXCTY_CC1				X						100%	100%	100%	100%	100%
CHAMON_CTG_0101		X												
CALHOUN_UNIT1														
THW_THWGT32		X												
WAP4_WAP4														
GBY_GBYGT74		X	X		100%	92%	33%*	0%*	50%					
PHR_CLCWA_5UNITS		X												
LH_LYN_30UNITS		X												
DSN_NEWP_10UNITS														
SOE_SEWP_10UNITS	X	X	X	X	100%	17%*	71%	100%	83%	100%	21%*	67%	100%	100%
FEGC_UNIT1				X						0%	0%	0%	0%	25%

Increasing the search radius from 10 km to 15 km picked up two additional air quality monitoring stations; however, the influence from the power station at that distance is substantially diminished, particularly in urban environments, where other sources of emissions will affect the monitor.

Tables 2a and 2b show the three highest monitored concentrations for NO_2, $PM_{2.5}$, and SO_2 over the 5-day period.[4] The only pollutant within 50 percent of the air quality standard was $PM_{2.5}$, although the $PM_{2.5}$ standard is an average over 24 hours, whereas those for NO_2 and SO_2 are 1-hour standards. No exceedances of any air quality standard occurred at these stations, nor at any air quality monitoring stations in the region of study. The highest concentration, to any air quality standard, was for the 24-hour $PM_{2.5}$ standard at 56 percent.

The highest elevated $PM_{2.5}$ concentrations all occurred during the late evening hours (8 p.m.–11 p.m.) on February 19, 2021. Many sources contribute to $PM_{2.5}$ pollution, including buses, trucks, cars, and off-road sources (e.g., construction equipment, portable generators). In addition, meteorology and atmospheric chemistry play a significant role in determining the air concentration. However, it is not possible from this analysis to estimate the source contribution from the power units without additional air quality modeling analysis.

Table 2a. Top 3 Highest Air Concentrations Monitored Within 10 km of the Power Generation Units

Power Unit	NO_2 (ppb)			$PM_{2.5}$ (µg/m^3)			SO_2 (ppb)		
Unit Code	**First**	**Second**	**Third**	**First**	**Second**	**Third**	**First**	**Second**	**Third**
DDPEC_CC1	37	33	29	17	12	11	1	1	1
FREC_CC2							0	0	0
TXCTY_CC1							3	2	2
CHAMON_CTG_0101	31	30	29						
THW_THWGT32	37	37	36						
GBY_GBYGT74	40	36	35	20	14	14			
PHR_CLCWA_5UNITS	27	18	17						
LH_LYN_30UNITS	31	30	29						
SOE_SEWP_10UNITS	37	33	29	17	12	11	1	1	1
FEGC_UNIT1							0	0	0

Note: For NO_2 and SO_2 these are 1-hour averages; $PM_{2.5}$ is a daily average.

Table 2b. Top 3 Highest Air Concentrations (as Percentage of Air Quality Standard[a]) Monitored Within 10 km of the Power Generation Units

Power Unit	NO_2			$PM_{2.5}$			SO_2		
Unit Code	**First**	**Second**	**Third**	**First**	**Second**	**Third**	**First**	**Second**	**Third**
	37%	33%	29%	48%	34%	30%	1%	1%	1%
FREC_CC2							0%	0%	0%
TXCTY_CC1							3%	3%	3%
CHAMON_CTG_0101	31%	30%	29%						
THW_THWGT32	37%	37%	36%						
GBY_GBYGT74	40%	36%	35%	56%	40%	39%			
PHR_CLCWA_5UNITS	27%	18%	17%						

[4] CO is not shown because the values were <1 percent of the NAAQS.

Power Unit	NO_2			$PM_{2.5}$			SO_2		
Unit Code	**First**	**Second**	**Third**	**First**	**Second**	**Third**	**First**	**Second**	**Third**
LH_LYN_30UNITS	31%	30%	29%						
SOE_SEWP_10UNITS	37%	33%	29%	48%	34%	30%	1%	1%	1%
FEGC_UNIT1							0%	0%	0%

[a] The 1-hour NO_2 standard is 100 ppb, 1-hour SO_2 standard is 75 ppb, and 24-hour $PM_{2.5}$ standard is 35 µg/m3.

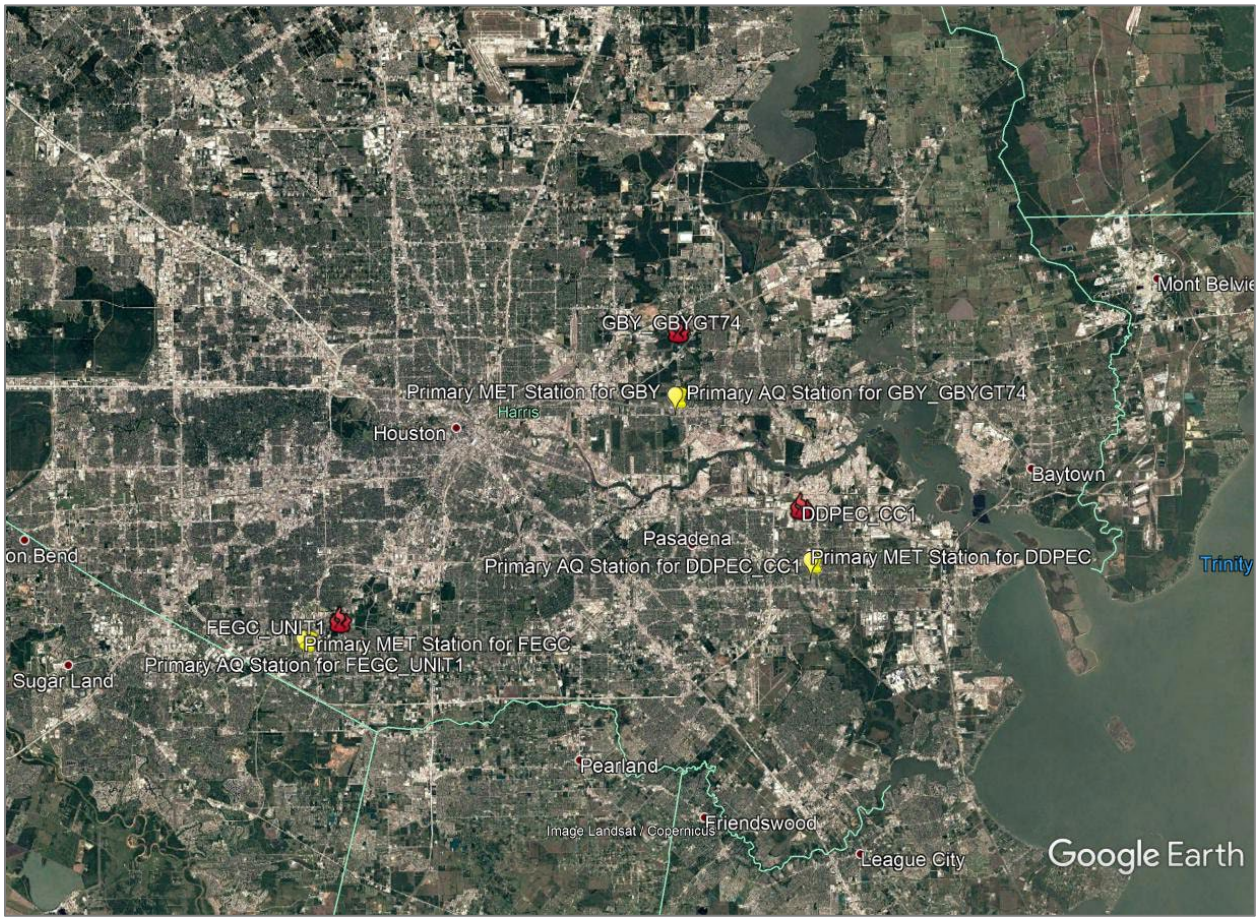
1.1.2 Downwind Air Quality Monitoring Sites

Besides being in close proximity to the power unit, an air quality monitoring station must also be oriented in the downwind direction of the power unit. Table 3 shows the percentage of time that the air quality monitoring station was downwind of the power unit. As shown, only one air quality monitoring site was downwind more than 50 percent of the hours. All other pairs of air quality monitoring stations and power units only had the correct alignment window 25 percent or less of the time. The air quality monitoring unit paired with the Deer Park Energy Center (DDPEC_CC1) power unit was downwind more than half the hours. This was the best pairing of any power unit and air quality station and shows good supporting evidence that the power units' excess emissions were unlikely to have caused an exceedance of the NAAQS (except on February 16, 2021, when the monitoring stations only had valid measurements for 20 percent of the hours that day). All other meteorological/air quality station pairs had too few hours to draw a conclusion. Figure 1 shows the locations of three of the power units relative to the air monitoring stations in Harris County.

Table 3. Power Unit Pairings With Nearby Meteorological Stations and Percentage of Time Downwind

Power Unit Code	Distance to MET Station (km)	AQ Station Direction – Lower Bound	AQ Station Direction – Upper Bound	% of MET Station Data Within +/-20 Degree Range of AQ Station Location
DDPEC	4.9	320°	360°	58%
FREC	10.3	320°	360°	25%
TXCTY	1.4	220°	260°	3%
CHAMON	8.6	0°	40°	6%
THW	17.5	220°	260°	<1%
GBY	5.6	345°	25°	25%
PHR	11.1	135°	175°	<1%
LH	1.2	100°	140°	10%
SOE	5.0	185°	225°	1%
FEGC	3.5	25°	65°	3%

Figure 1. Location of Three Power Units Operating in Harris County and the Paired Air Monitoring Station



1.1.3 Meteorological Conditions Conducive to High Concentrations

Wind Speed

As discussed, lower wind speeds result in poorer dispersive conditions that lead to higher air concentration levels. Average wind speeds for February, based on the 23-year average (1998–2020) from the Houston Aldine site (EPA Airs ID# 48-201-0024), is 6.2 mph. During the 5-day emergency-use period, the winds were slightly higher (14 percent) than the average wind speed of 7.0 mph. Thus, the slightly higher wind speeds are favorable to having lower air concentrations.

Temperature

As discussed, lower temperatures will lead to increased buoyancy, resulting in lower air concentrations. The climatological average air temperature for February at the Houston International Airport is 57.7°F. During the 5-day event, the average air temperature was 28.4°F, almost 30°F below average. These substantially colder temperatures are favorable to having lower ground-level air concentrations, assuming the plume rise from the power units is sufficiently high that these concentrations are not trapped in a shallow stable layer (i.e., temperature inversion) near the surface.

Mixing Heights

We determined mixing height by using the same method as the historical data from Lake Charles (the closest upper air station to Harris County). The February morning mean mixing height during the 5-day emergency event was 530 m, and the afternoon mixing height was 607 m. This compares with a climatological morning mixing height of 319 m in February and a climatological afternoon mixing height of 822 m. The higher mixing height observed during the event reduced the tendency for the trapping of air pollutants in a shallow layer near the Earth's surface, so air concentrations should be lower due to higher mixing height. The lower mixing heights observed during the event in the afternoon relative to the climatological average is the reverse of the morning, but the mean depth of the mixed layer is still higher than the morning period, so in general, concentrations are lower in the afternoon than the morning if emissions are the same.

1.1.4 Emission Rates: ERCOT versus CEMS

To better understand the emissions data, we graphically displayed the ratio of the ERCOT emission rates for NO_X to the CEMS NO_X emission rates for every hour using three representative emission profiles observed during our review of the ERCOT dataset. We report results for three representative types of findings. These are:

1. Peaking Plant, where the ERCOT is thought to be a large fraction of the CEMS data
2. Large amount of volatility in the ERCOT dataset
3. Does not make sense (ERCOT emission rate >> CEMS emission rate)

In no case should the ERCOT to CEMS ratio be greater than 1.

The three representative stations are:

1. Port Comfort Peaking Unit 2
2. Chamon Power Unit 1
3. Bosque CCP-GT-1

Figure 2 shows the ratio of the ERCOT NO_X emission rate to the CEMS NO_X emission rate for Port Comfort Peaking unit, with most hours reporting a ratio between 60 to 80 percent of the CEMS emission rate and with the unit off during most of February 18, 2021. A few anomalous hours occur where the ERCOT-to-CEMS ratio exceeds 1. Overall, this pattern appears to be a reasonable behavior.

Figure 2. Port Comfort Peaking Unit Hourly ERCOT/CEMS Emission Ratio During Emergency Period

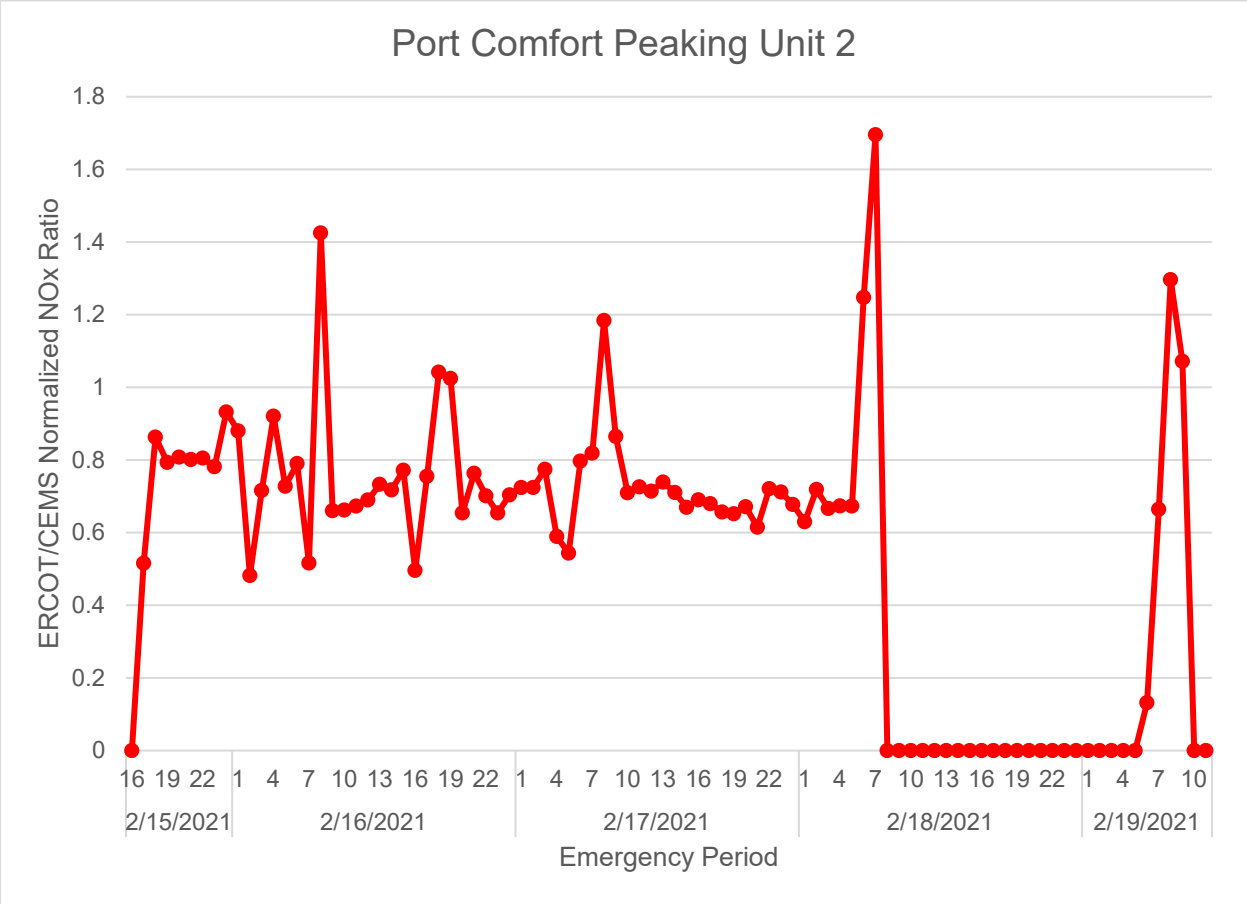


Figure 3 shows the ratio of the ERCOT NO_X emission rate to the CEMS NO_X emission rate for the Port Chamon unit, with most hours having a value of less than 100 percent. There are a few hours with a ratio excursion that well exceeds a ratio of 1. Overall, this pattern can likely be explained if further information can be obtained from the plant about the few hourly ratio excursions that were much greater than 1.

Figure 3. Chamon Unit 1 Hourly ERCOT/CEMS Emission Ratio During Emergency Period

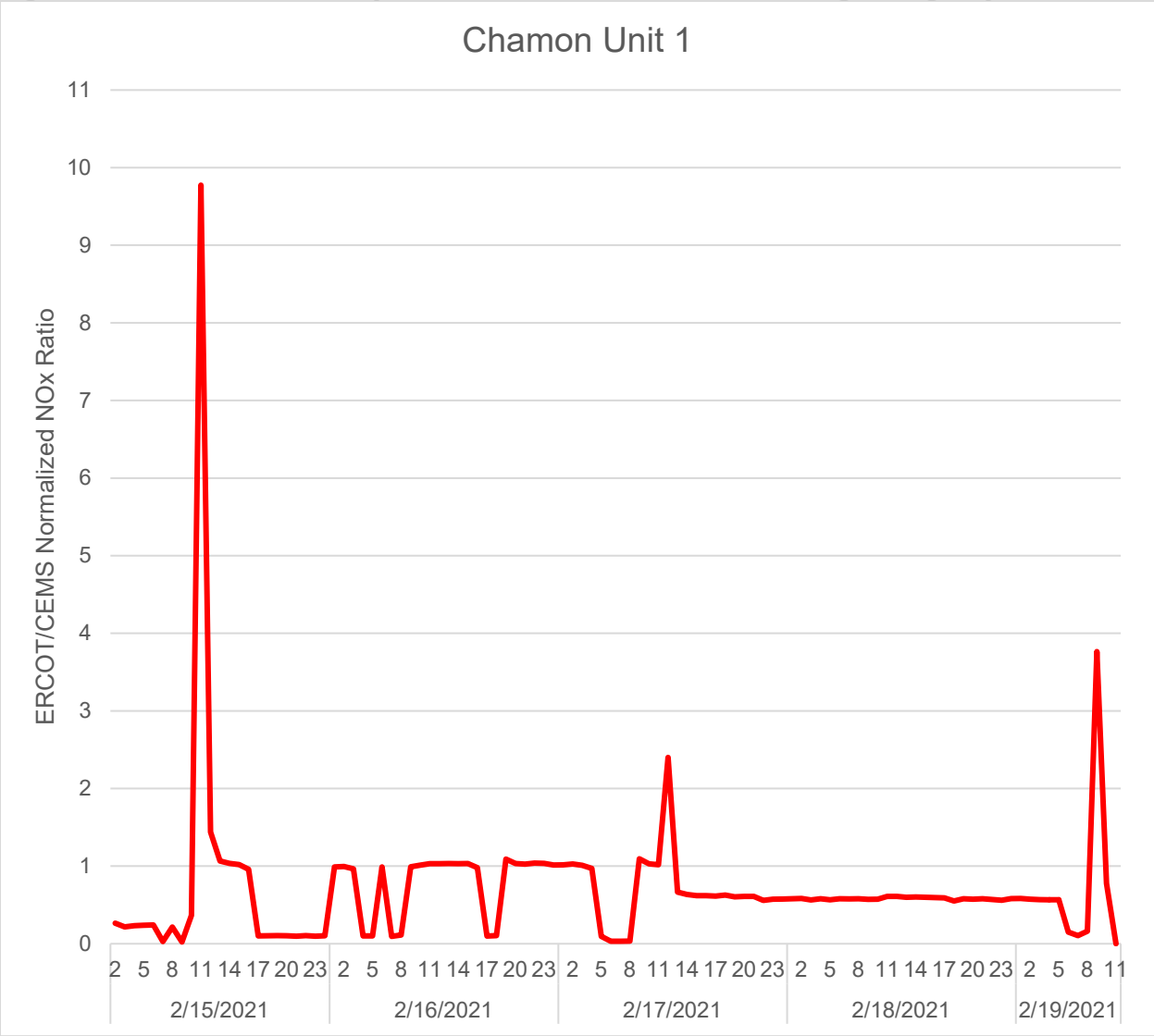
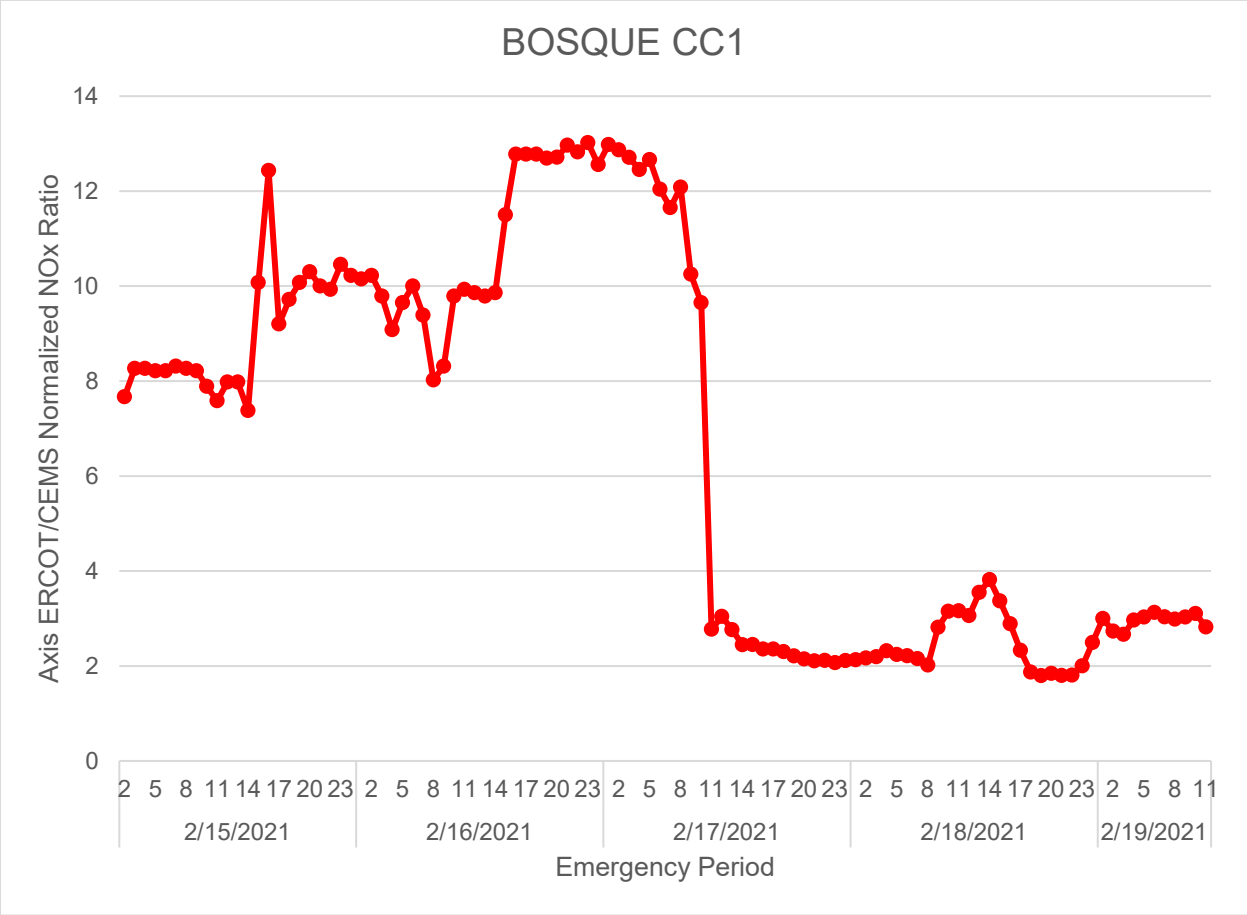


Figure 4 shows the ratio of the ERCOT NO_X emission rate to the CEMS NO_X emission rate for the BOSQUE unit, with all hours having a ratio in excess of 1, or less than 100 percent, but a few hours having a ratio excursion that well exceeds a ratio of 1. In fact, no ratio is less than 2, with a maximum of 13. Overall, these high values in comparison to the CEMS data are irregular. We suspect that incorrect values may have been reported by BOSQUE, as well as other units that exhibited similar behavior. However, further discussion with the plant is needed to clarify this finding.

Figure 4. BOSQUE Unit 1 Hourly ERCOT/CEMS Emission Ratio During Emergency Period



1.2 Conclusions – Air Quality Analysis

We reviewed ambient air quality monitoring data, meteorological data, and emission information for the power units that operated in exceedance of their permitted levels during the emergency use of power generation authorization under Section 202(c). We paired air quality monitoring stations with power units that were near each other. We found parings for 10 of the 14 unique power generation units, most often for NO_2. We found no exceedances of the NAAQS standards; however, many of the air quality stations were missing air quality measurements on February 16 and 17, 2021. The highest concentration, to any air quality standard, was for the 24-hour $PM_{2.5}$ standard at 56 percent of the exceedance threshold value. Further review of the air quality monitoring station and power unit data showed just one air quality monitoring station downwind of the power unit for the majority of hours during the emergency use period. A review and discussion of the meteorological conditions (e.g., wind speeds, temperature, mixing heights)

during the emergency period showed that the meteorology was conducive to better mixing and dispersion than average conditions in February. Reported incremental emissions did not compare favorably with the CEMS data available for NO_X.

Although no exceedances for the NAAQS occurred during the emergency use period, the large percentage of missing data, particularly on February 16 and 17, 2021, make it difficult to conclusively conclude that no violation of the NAAQS may have occurred. Furthermore, the limited number of downwind air quality monitors in close proximity to the power units makes it difficult to definitively conclude there were no air quality exceedances. However, based on the weight-of-evidence approach presented herein, it appears unlikely that the power units may have caused an exceedance of the NAAQS.

2 Environmental Justice Implications for the Affected Population

This section highlights the potential environmental justice (EJ) implications of the affected population in the region of interest. Our evaluation was based on data from U.S. Environmental Protection Agency's (EPA) EJSCREEN tool, available at ejscreen.epa.gov/mapper. EJSCREEN is a tool EPA has developed over the years to allow users to evaluate potential EJ impacts in different parts of the country using a GIS-based mapping platform. The tool allows users to combine demographic and environmental information on a user-selected area. The data used for these purposes in EJSCREEN are based on publicly available data sources, such as the American Community Survey from the Census Bureau for demographic data and various EPA data sources for environmental indicators. We used this screening tool for this analysis because it provides a method consistent with EPA's approach for defining EJ vulnerabilities for affected populations.

2.1 Analyzing Demographic Characteristics of Nearby Population

In order to identify the vulnerable population around these 14 unique power plants and 27 units that are likely to be impacted by any potential exceedances during the 5-day period, we extracted the demographic and environmental characteristics of those living with a pre-specified 5- and 10-km radius around each power plant. Note that we conducted this analysis at the plant level (as opposed to the unit level) because the unique location coordinates were available only at the plant level.

Figure 5 below overlays the 5-km circles around the individual power plants. Most of the plants are located around the Houston area, with a few farther away. Populations living around plants in the Houston area are likely to be more susceptible to potential EJ concerns. There is an overlap between the Lynchburg (LH) and Deer Park Energy Center (DDPEC) plant radii, as well as between the DDPEC and Southeast WPP (SOE) plant radii. Individuals in the intersections may experience EJ effects from both plants, and therefore may be more affected.

Figure 5. 5-km Radius Around Plants

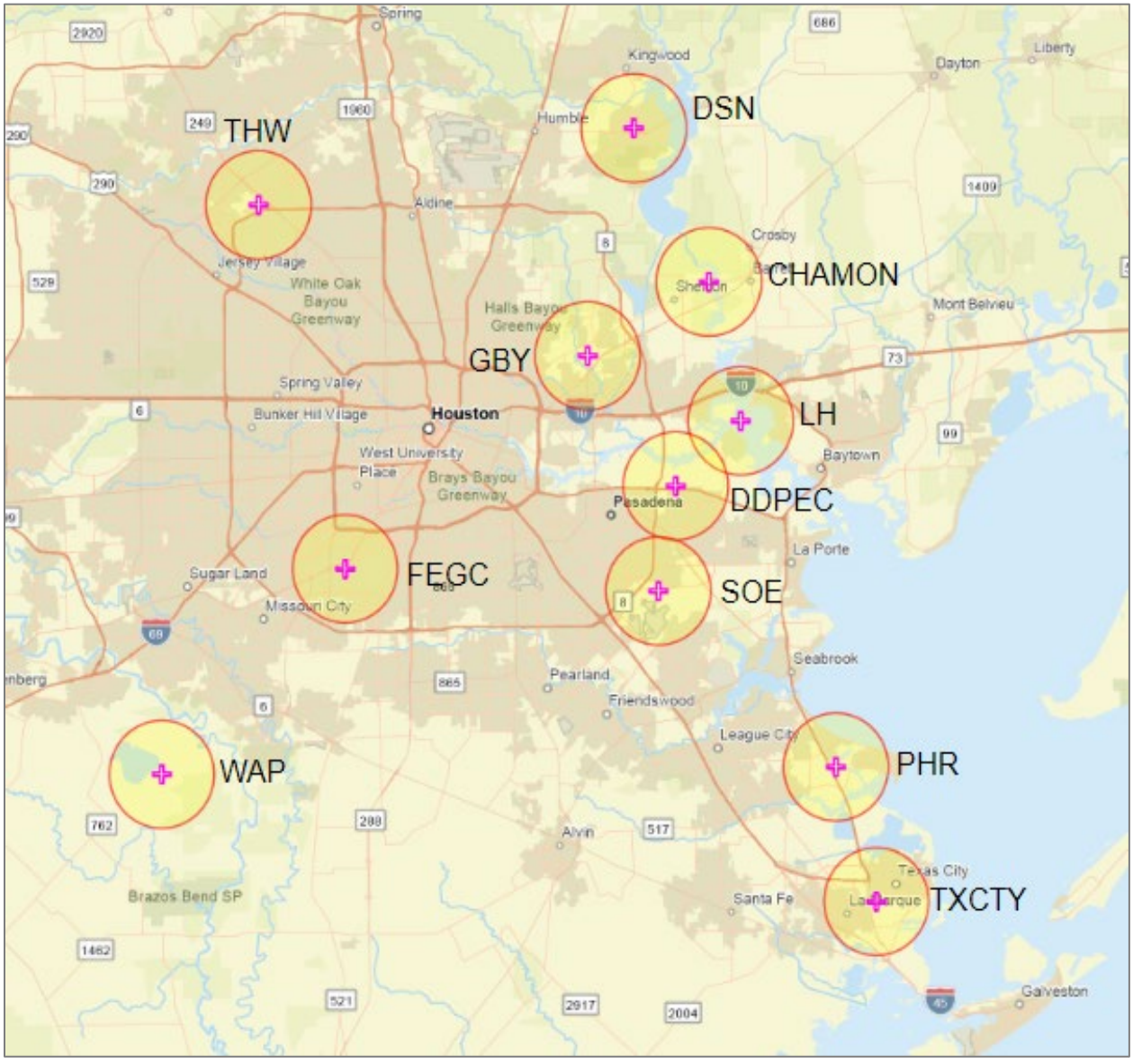
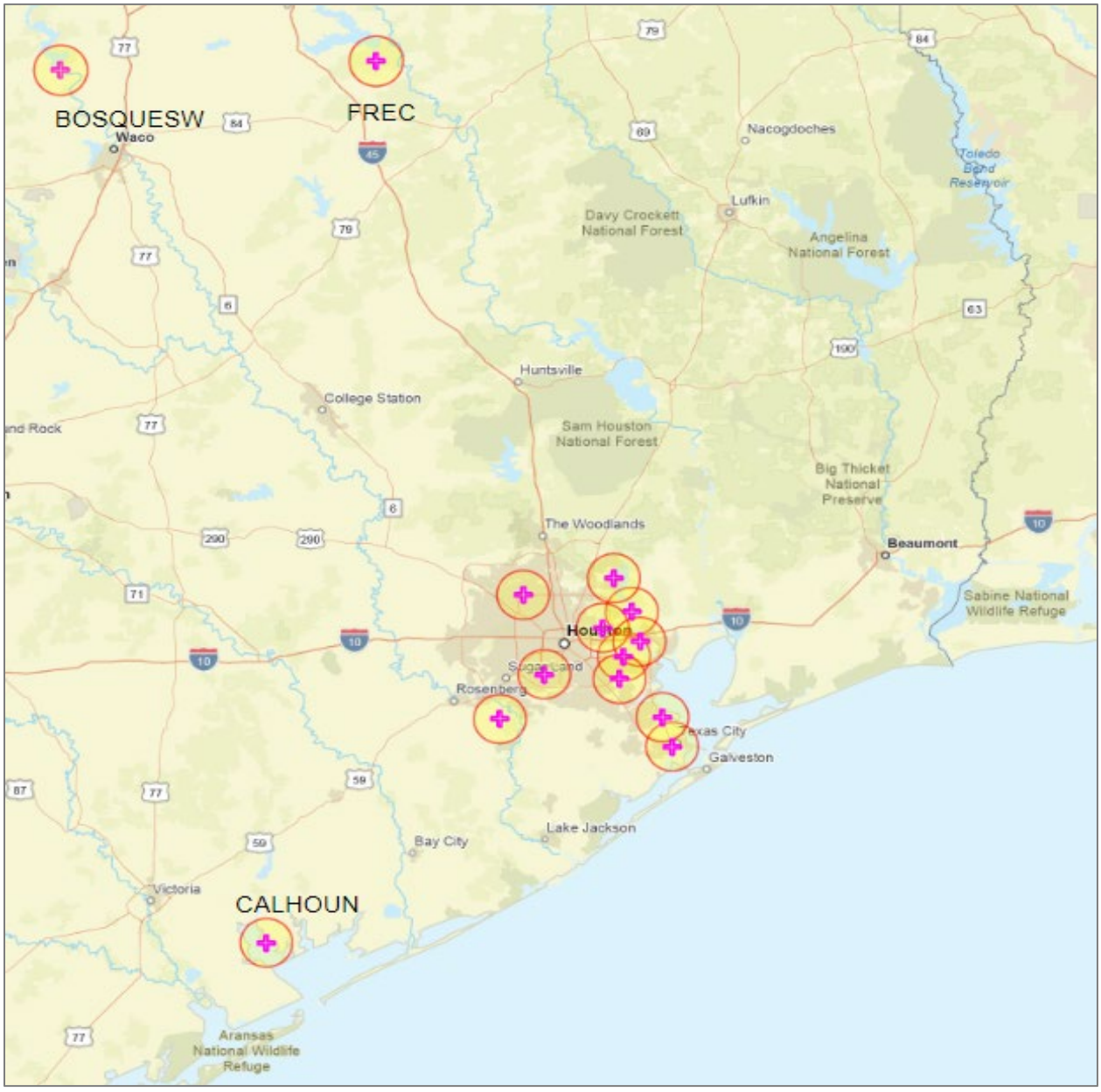


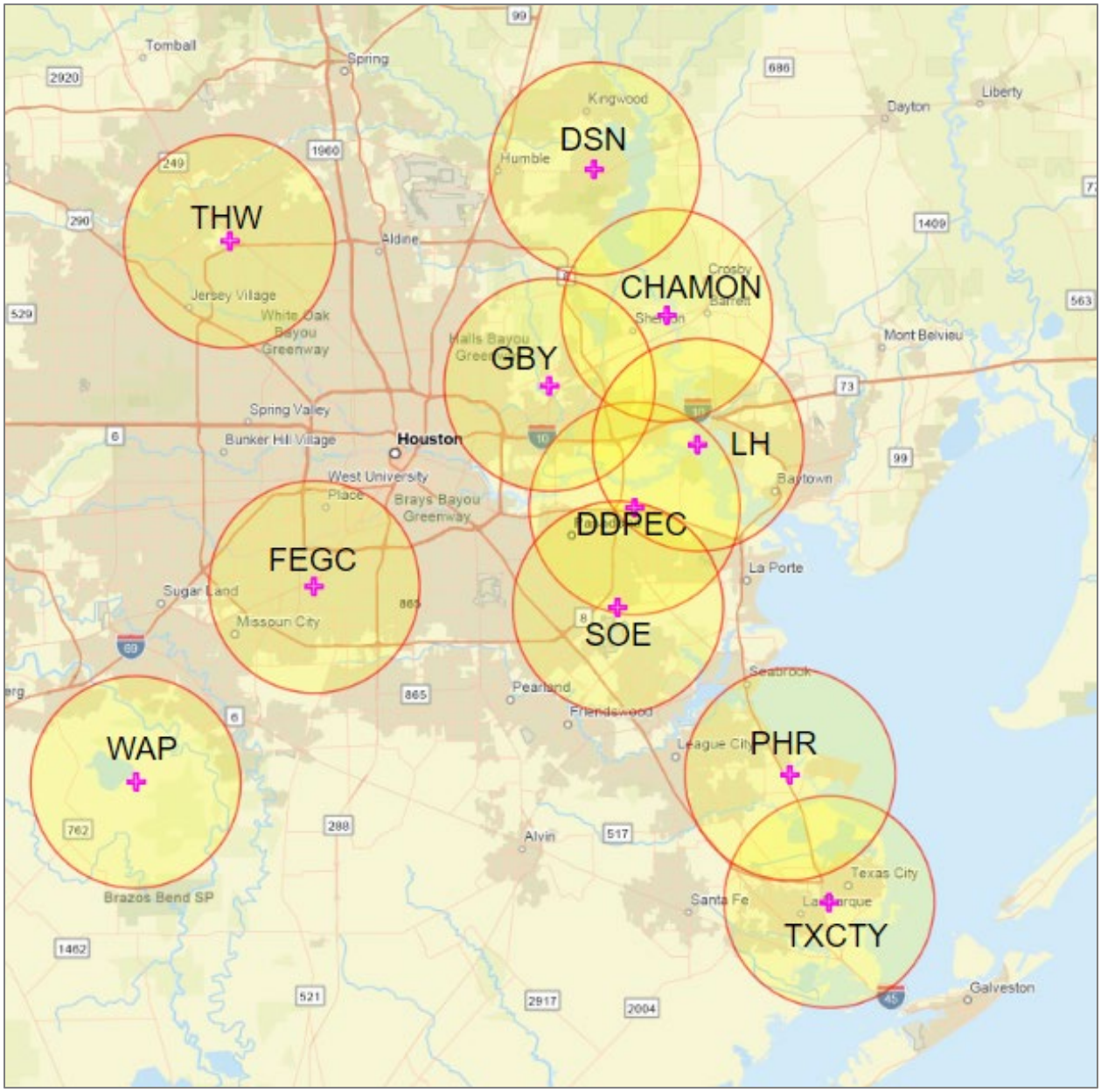
Figure 6 below overlays 10-km circles around the individual power plants. Using a 10-km radius around these plants captures a greater share of the potentially affected population and is consistent with the air quality analysis discussed above. It also creates more overlapping areas, which increases the EJ concerns for the people living in those areas. This is discussed in more detail below.

Figure 6. 10-km Radius Around Plants



Given the relative proximity of some of these plants, particularly those in the Houston area, several of the 10-km circles tended to have some overlapping areas among them, which suggests that some members of the population are likely to be affected by activities from multiple plants and are therefore exposed to higher EJ risks than others. In order to analyze those risks, Figure 7 below focuses on the plants around Houston to identify intersecting circles.

Figure 7. Intersecting Areas With 10-Km Radius Around the Plants



Using these custom boundaries, ICF extracted demographic and enviromental data from EJSCREEN to identify potential EJ vulnerabilities for the population living around these plants. Table 4 indicates the age ranges of populations in both the 5- and 10-km radii from the power plant indicated. As the table shows, there is a wide variablity of the exposure in the 5- and 10-km ranges around these plants. The total population exposed to any potential EJ concerns within a

5-km radius of these plants can range from about 50 people to over 100,000 people, with FREC being the lowest and FEGC being the highest. Similar patterns hold for the 10-km radii, except the range is from about 900 to over 500,000 people.

Table 4. Distribution of the Affected Population by Age

	5-Km Radius					10-Km Radius				
Power Plant	**Total Population**	**0 to 4**	**5 to 17**	**18 to 64**	**65+**	**Total Population**	**0 to 4**	**5 to 17**	**18 to 64**	**65+**
BOSQUE	**1,989**	5%	12%	55%	29%	**4,176**	4%	13%	55%	28%
CALHOUN	**751**	10%	17%	65%	8%	**11,735**	7%	17%	59%	17%
CHAMON	**10,469**	6%	20%	60%	15%	**90,052**	9%	21%	62%	8%
DDPEC	**53,680**	7%	21%	61%	10%	**276,938**	8%	22%	61%	9%
DSN	**67,599**	8%	22%	61%	9%	**201,458**	7%	21%	61%	11%
FEGC	**112,417**	7%	18%	63%	12%	**568,858**	8%	18%	64%	10%
FREC	**56**	4%	20%	61%	16%	**868**	5%	16%	65%	14%
GBY	**79,700**	9%	21%	62%	8%	**258,116**	8%	22%	61%	9%
LH	**12,839**	9%	21%	57%	14%	**128,113**	8%	22%	61%	10%
PHR	**18,722**	9%	19%	62%	10%	**93,580**	8%	19%	61%	12%
SOE	**56,345**	6%	18%	63%	13%	**394,451**	8%	20%	62%	10%
THW	**107,393**	7%	20%	63%	10%	**461,570**	7%	20%	63%	10%
TXCTY	**43,452**	8%	19%	59%	15%	**71,729**	7%	18%	60%	16%
WAP	**745**	8%	20%	61%	11%	**54,391**	7%	23%	61%	10%

The majority of the people living in these areas seem to fall into what is likely the least vulnerable from an age perspective for EJ concerns. As the table above shows, more than 50 percent of the population falls within the 18–64 age group. However, some of these plants do have a relatively large share of the population that can be considered to be more susceptible to EJ problems. For example, BOSQUE has the highest percentage of people age 65+ in a 5- and 10-km radius, but is among the lowest in total population. Also, four of these plants have roughly 30 percent of the population below the age of 18, with about 20 percent or so in the 5–17 age group and the remaining 10 percent or so in the 0–4 age group.

Table 5 shows the distribution of the population by household incomes in both the 5- and 10-km radii. Note that the income data presented below are for households and not in per capita terms, which is different from how the data are shown in the other demographic tables.

Many of these plants have a relatively large share (20–30 percent) of the households that have incomes less than $25,000 or close to the federal poverty line. Among them, GBY and TXCTY have the highest percentage (13 percent for the 10-km radius) of people with incomes below $15,000 for a household, which is likely to exacerbate potential EJ concerns for this region. Correspondingly, GBY and TXCTY have the lowest percentage of people with a household income above $50,000, falling between 40 and 50 percent for both radii. This indicates that the majority of people in these radii have household incomes below $50,000, and both of these power plants are among those with a larger surrounding population.

Table 5. Distribution of the Affected Households by Income

	5-Km Radius					10-Km Radius				
Power Plant	**Total Households**	**< $15,000**	**$15,000–$25,000**	**$25,000–$50,000**	**$50,000 +**	**Total Households**	**< $15,000**	**$15,000–$25,000**	**$25,000–$50,000**	**$50,000 +**
BOSQUE	**809**	10%	14%	23%	52%	**1,812**	11%	15%	22%	52%
CALHOUN	**285**	7%	7%	20%	65%	**4,137**	11%	8%	27%	53%
CHAMON	**3,418**	7%	8%	23%	62%	**28,248**	7%	7%	20%	66%
DDPEC	**16,779**	7%	9%	21%	63%	**85,473**	9%	10%	24%	56%
DSN	**22,212**	4%	4%	13%	78%	**67,417**	6%	5%	15%	74%
FEGC	**39,063**	11%	8%	21%	59%	**207,938**	12%	11%	22%	55%
FREC	**30**	10%	17%	17%	57%	**533**	10%	20%	19%	51%
GBY	**24,514**	11%	11%	30%	48%	**77,689**	13%	13%	30%	45%
LH	**4,234**	12%	10%	23%	55%	**39,892**	10%	9%	23%	59%
PHR	**6,527**	11%	12%	21%	56%	**34,256**	9%	8%	18%	64%
SOE	**19,748**	7%	7%	19%	68%	**130,051**	9%	8%	23%	60%
THW	**34,429**	7%	9%	25%	59%	**155,731**	8%	8%	24%	60%
TXCTY	**15,489**	15%	13%	30%	41%	**26,149**	13%	12%	27%	48%
WAP	**307**	2%	1%	9%	88%	**16,375**	3%	2%	8%	86%

The table below shows the breakdown of the population in these regions by race, in both the 5-km and 10-km radii. Race information is broken down to show populations that self-identify as Black, Hispanic, Other non-White (i.e., American Indian, non-Hispanic Asian, Pacific Islander, or another race), and White.

Not surprisingly, some of the regions with the lowest income distribution also have the largest minority populations. For example, the area around GBY, which had one of the largest shares of the low-income population, also has around 90 percent Black and Hispanic populations. TXCTY, which also had a high proportion of the low-income population around it, is about two-thirds Black and Hispanic. Among the others, the population around FEGC, THW, and LH is also high in non-White or minority populations.

Table 6. Distribution of Population by Race

	5-Km Radius					10-Km Radius				
Power Plant	**Total Population**	**Black**	**Hispanic**	**Other Non-white**	**White**	**Total Population**	**Black**	**Hispanic**	**Other Non-white**	**White**
BOSQUE	**1,989**	1%	7%	1%	91%	**4,176**	1%	7%	1%	90%
CALHOUN	**751**	5%	29%	9%	57%	**11,735**	4%	55%	7%	34%
CHAMON	**10,469**	21%	39%	3%	38%	**90,052**	18%	46%	4%	32%
DDPEC	**53,680**	2%	55%	2%	41%	**276,938**	4%	65%	2%	29%
DSN	**67,599**	17%	27%	6%	51%	**201,458**	15%	25%	5%	54%
FEGC	**112,417**	32%	39%	7%	22%	**568,858**	31%	35%	11%	23%
FREC	**56**	13%	7%	4%	77%	**868**	24%	7%	4%	65%
GBY	**79,700**	30%	59%	2%	9%	**258,116**	29%	61%	2%	9%
LH	**12,839**	7%	51%	3%	40%	**128,113**	14%	53%	4%	29%
PHR	**18,722**	4%	33%	7%	55%	**93,580**	9%	27%	5%	59%
SOE	**56,345**	3%	42%	10%	45%	**394,451**	6%	55%	7%	32%
THW	**107,393**	20%	40%	16%	24%	**461,570**	21%	39%	12%	29%
TXCTY	**43,452**	29%	32%	5%	34%	**71,729**	27%	29%	4%	40%
WAP	**745**	19%	22%	11%	48%	**54,391**	11%	13%	34%	41%

2.2 Combining Demographic Information With Environmental Indicators

In order to understand the EJ vulnerabilities of the population living around these power plants, we analyzed various pollutant indicators from EJSCREEN and used their estimated percentile rankings to compare the potential vulnerabilities across the various plants. The estimated percentile rankings, developed by EPA, combine the environmental indicator with the appropriate demographic data to account for the vulnerable groups in the calculation of the EJ indicator. In this context, EPA defines the vulnerable groups as the average of the count of minorities and low-income households. In terms of the individual percentile rankings, a low number signifies that this group is relatively better off than the rest of the state population, whereas a high ranking signifies a relatively worse off situation than the rest of the state. As an example, if a certain ranking is 80, it means that this place is at the 80th percentile, which implies that only 20 percent of the state population experiences pollution that is higher than those experienced by people in this region. Thus, as a general principal, percentile rankings that are on the high side generally imply the region in question is comparatively worse off than other places in the state.

Table 7 shows the relative rankings of the various populations around these plants that are exposed to the various environmental indicators of interest (see Table 7 notes for definitions of these pollutant indicators). We present the percentile rankings for both the 5- and 10-km radii around each power plant. Table 7 also presents a calculated average percentile ranking in order for us to easily compare across the various plants. Average percentile rankings greater than 50 percent are highlighted in light blue and indicated with an asterisk (*). Note that these averages are simple arithmetic means, which essentially puts equal weights on each environmental indicator, irrespective of their implications on human health. Thus, one could argue that these averages are not reflective of the individual pollutants' effect on the vulnerable populations. We included them here for easy comparison across the groups without any value judgement on the individual pollutants.

Table 7. Percentile Ranking of Various Environmental Indicators

	5-Km Radius					
Power Plant	**Particulate Matter ($PM_{2.5}$ in ug/m3)**	**NATA Diesel PM (ug/m3)**	**NATA Air Toxics Cancer Risk (risk per MM)**	**NATA Respiratory Hazard Index**	**Hazardous Waste Proximity (facility count/km distance)**	**Average Percentile Ranking**
BOSQUE	26	30	28	28	35	**29.4**
CALHOUN	40	38	40	40	50	**41.6**
CHAMON	57	59	69	62	60	**61.4***
DDPEC	52	62	64	54	85	**63.4***
DSN	16	16	12	15	25	**16.8**
FEGC	80	87	83	81	93	**84.8***
FREC	31	33	31	31	32	**31.6**
GBY	91	92	95	95	96	**93.8***
LH	62	67	84	68	95	**75.2***
PHR	41	40	40	40	49	**42**
SOE	44	51	50	46	66	**51.4***
THW	83	90	83	85	93	**86.8***
TXCTY	62	61	61	61	92	**67.4***
WAP	11	13	12	12	20	**13.6**
	10-Km Radius					
Power Plant	**Particulate Matter ($PM_{2.5}$ in ug/m3)**	**NATA Diesel PM (ug/m3)**	**NATA Air Toxics Cancer Risk (risk per MM)**	**NATA Respiratory Hazard Index**	**Hazardous Waste Proximity (facility count/km distance)**	**Average Percentile Ranking**
BOSQUE	22	27	23	23	33	**25.6**
CALHOUN	51	48	48	47	46	**48**
CHAMON	81	80	94	87	94	**87.2***
DDPEC	70	77	85	79	95	**81.2***
DSN	30	32	28	30	50	**34**
FEGC	77	86	80	78	87	**81.6***
FREC	48	44	48	48	42	**46**
GBY	89	91	95	94	97	**93.2***
LH	78	80	92	87	96	**86.6***
PHR	31	26	26	30	58	**34.2**
SOE	66	75	77	69	86	**74.6***
THW	78	86	79	80	87	**82***
TXCTY	56	56	56	56	87	**62.2***
WAP	50	54	49	49	48	**50**

Particulate Matter ($PM_{2.5}$ in ug/m3) – $PM_{2.5}$ levels in the air, measured in µg/m3 annual average.

NATA Diesel PM (ug/m3) – Diesel particulate matter level in the air, measured in µg/m3.

NATA Air Toxics Cancer Risk (risk per MM) – Lifetime cancer risk from inhalation of air toxics.

NATA Respiratory Hazard Index – Air toxics respiratory hazard index (the ratio of exposure concentration to health-based reference concentration).

Hazardous Waste Proximity (facility count/km distance) – The count of hazardous waste facilities (TSDFs and LQGs) within 5 km (or nearest beyond 5 km), each divided by the distance in kilometers.

In order to identify which of these regions may have a vulnerable population exposed to disproportionately higher environmental justice concerns than the rest of the state, we chose an arbitrary 50-percent threshold and highlighted in the tables above those regions that are above that threshold. The results imply that the vulnerable populations living in these regions are experiencing higher levels of EJ concerns than a majority of the rest of Texas. Unsurprisingly, among these regions around power plants that are of higher EJ concerns, the ones that we identified above as having the most vulnerable populations are the ones with the highest average ranking. This includes populations around power plants GBY, FEGC, and THW as the most at-risk, with an average percentile ranking of over 80. Following those are SOE, LH, and TXCTY, with rankings between 60 and 70. Some power plants seem to jump considerably, moving from the 5-km to the 10-km radii. These include CHAMON and DDPEC, where the rankings jump from the 60s to 80s when we move from the 5-km to 10-km radius. Thus, when we analyze the vulnerable population within a 10-km radius of these plants, the majority of these power plants (i.e., 8 out of 14) have a baseline EJ vulnerability, higher than the rest of the state, affecting the population living near these power plants.

2.3 Population in Close Proximity to Multiple Plants

As discussed previously (see Figure 7), several of these power plants, particularly those around the Houston area, have significant overlapping regions when we analyze the populations within a 10-km radius around these plants. Populations living in these “intersecting circles” are likely to face even higher EJ concerns, given that they may have been exposed to higher emissions from multiple power plants. Here we present data for these population groups in these intersecting circles and their potential for higher EJ concerns.

Table 8 below shows the age distribution of the population living in these intersecting regions with two or more 10-km radii. The intersecting radii are of different sizes, which is part of the reason for the differences in population between areas. Overall, the percentage of people in each intersecting region that are between ages 0 and 4 are comparable to those 65+, with the latter only a slightly higher percentage in most areas. In total, approximately 12 percent, or about 325,000 of the 2.6 million total population living within a 10-km radius of all power plants, live in these intersecting regions and are thus likely to face higher levels of baseline EJ concerns than those that live outside of these intersecting regions. Most of this population group lives in an area that has two plants within 10 km, but about 20 percent of them live in areas that are close to three or more power plants.

Table 8. Distribution of the Affected Population in the Intersecting Regions by Age

	10-Km Radius Intersections				
Power Plants	**Total Population**	**0 to 4**	**5 to 17**	**18 to 64**	**65+**
CHAMON & DSN	**14,817**	10%	19%	65%	5%
GBY & CHAMON	**21,330**	10%	21%	63%	6%
GBY & DDPEC	**22,002**	9%	23%	60%	8%
LH & CHAMON	**11,605**	7%	20%	61%	12%
LH & DDPEC	**6,337**	10%	20%	60%	10%
LH & GBY	**1,073**	3%	22%	66%	10%
PHR & TXCTY	**8,678**	7%	17%	61%	16%
SOE & DDPEC	**175,158**	8%	21%	61%	10%
DDPEC & LH & GBY	**28,277**	8%	25%	59%	8%
GBY & LH & CHAMON	**10,371**	8%	25%	62%	6%
LH & DDPEC & CHAMON	**3,495**	9%	24%	56%	10%
LH & DDPEC & SOE	**15,072**	5%	19%	65%	11%
DDPEC & LH & GBY & CHAMON	**7,275**	7%	25%	62%	5%

Table 9 shows the household income of populations living in intersections of two or more 10-km radii. Household incomes for the intersecting regions are comparable to the incomes of the 5- and 10-km radii. Two intersecting areas have a majority of households with incomes less than $50,000, which are the LH/DDPEC/CHAMON intersection and the GBY/DDPEC intersection. Alternatively, the highest percentage of households with incomes over $50,000 is 81 percent, in the intersection of CHAMON and DSN.

Table 9. Distribution of the Affected Population in the Intersecting Regions by Income

	10-Km Radius Intersections				
Power Plants	**Total Households**	**< $15,000**	**$15,000–$25,000**	**$25,000–$50,000**	**$50,000 +**
CHAMON & DSN	**4,652**	3%	4%	12%	81%
GBY & CHAMON	**6,424**	4%	5%	26%	65%
GBY & DDPEC	**6,320**	12%	15%	29%	44%
LH & CHAMON	**3,972**	9%	11%	24%	56%
LH & DDPEC	**1,989**	11%	12%	24%	54%
LH & GBY	**281**	2%	2%	20%	76%
PHR & TXCTY	**3,095**	13%	9%	25%	53%
SOE & DDPEC	**55,947**	10%	10%	24%	57%
DDPEC & LH & GBY	**7,730**	7%	12%	29%	52%
GBY & LH & CHAMON	**2,873**	6%	3%	20%	71%
LH & DDPEC & CHAMON	**959**	13%	20%	21%	46%
LH & DDPEC & SOE	**4,917**	2%	5%	17%	75%
DDPEC & LH & GBY & CHAMON	**2,081**	8%	5%	20%	67%

Table 10 below shows the racial composition of the population living in intersections of two or more 10-km substation radii. Most of these intersecting regions have a predominantly minority population, with the Hispanic population comprising the bulk. The intersection with the highest total population is also among the highest in percentage of non-Whites, SOE/DDPEC. With a population over 100,000 greater than the next largest population, 69 percent of the population is either Black, Hispanic, or another non-White race. Other areas with a high percentage of non-White races are GBY/LH/CHAMON, DDPEC/LH/GBY/CHAMON, and LH/GBY.

Table 10. Distribution of the Affected Population in the Intersecting Regions by Race

	Race of Population				
	10-Km Radius Intersections				
Power Plants	**Total Population**	**Black**	**Hispanic**	**Other Non-White**	**White**
CHAMON & DSN	**14,817**	21%	28%	5%	46%
GBY & CHAMON	**21,330**	24%	54%	6%	16%
GBY & DDPEC	**22,002**	4%	82%	1%	13%
LH & CHAMON	**11,605**	7%	47%	1%	44%
LH & DDPEC	**6,337**	0%	56%	1%	43%
LH & GBY	**1,073**	37%	44%	7%	12%
PHR & TXCTY	**8,678**	19%	28%	4%	48%
SOE & DDPEC	**175,158**	2%	64%	3%	31%
DDPEC & LH & GBY	**28,277**	11%	72%	1%	16%
GBY & LH & CHAMON	**10,371**	22%	66%	3%	9%
LH & DDPEC & CHAMON	**3,495**	0%	67%	2%	31%
LH & DDPEC & SOE	**15,072**	0%	29%	6%	65%
DDPEC & LH & GBY & CHAMON	**7,275**	25%	65%	2%	9%

Table 11 below shows the EJ indexes in intersections of two or more 10-km substation radii. As discussed above, the environmental indicator listed in the Table 11 incorporates the value of the pollutant within the radius, as well as the percentage of minority people and low-income people in the radius. The table also presents the “average” percentile ranking as a way to ordinally rank these intersecting circles. Average percentile rankings greater than 50 percent are highlighted in light blue and indicated with an asterisk (*).

Table 11. Environmental Justice Index in State Percentiles for People Living in the Intersecting Points of Two or More Substations in a 10-km Radius

	10-Km Radius Intersections					
Power Plants	**Particulate Matter (PM 2.5 in ug/m3)**	**NATA Diesel PM (ug/m3)**	**NATA Air Toxics Cancer Risk (risk per MM)**	**NATA Respiratory Hazard Index**	**Hazardous Waste Proximity (facility count/km distance)**	**Average Percentile Ranking**
CHAMON & DSN	42	44	43	43	41	**42.6**
GBY & CHAMON	94	93	97	96	94	**94.8***
GBY & DDPEC	78	85	89	94	98	**88.8***
LH & CHAMON	54	60	71	59	75	**63.8***
LH & DDPEC	64	69	90	72	97	**78.4***
LH & GBY	68	73	81	79	94	**79***
PHR & TXCTY	65	62	65	63	87	**68.4***
SOE & DDPEC	64	74	78	68	92	**75.2***
DDPEC & LH & GBY	88	89	97	96	99	**93.8***
GBY & LH & CHAMON	96	95	99	98	99	**97.4***
LH & DDPEC & CHAMON	78	80	97	84	98	**87.4***
LH & DDPEC & SOE	13	10	2	10	0	**7**
DDPEC & LH & GBY & CHAMON	95	93	99	97	99	**96.6***

Using the same 50 percent threshold, the table shows which of these intersecting circles have a value higher than 50 percent, which implies that the population living in these intersecting regions have a higher level of exposure to EJ concerns than a majority of the rest of the population in Texas. Only two intersections have an average state percentile under 50 percent, which are LH/DDPEC/SOE and CHAMON/DSN. Thus, almost 85 percent of the population living in these intersecting regions have higher exposure to EJ concerns than the rest of the state. Given that these population groups, consisting mostly of minority populations, live near multiple power plants (and presumably other stationary sources), it is not surprising that these groups are more vulnerable when it comes to environmental justice considerations compared to the rest of the state.

2.4 Conclusion – Environmental Justice Analysis

Using data from EPA's EJSCREEN, it appears that people of color and those with limited socioeconomic means in and around the Houston area are more vulnerable to environmental justice considerations compared to the rest of Texas. Given the paucity of data discussed in the air quality analysis above, we could not determine whether the EJ concerns for these groups were exacerbated during those 5 days in February 2021, when DOE authorized the emergency use of power generation under Section 202(c) of the Federal Power Act. However, analyzing the *baseline, business-as-usual* EJ concerns for the population around these power plants does indicate that a majority of the population living here are minority with limited socioeconomic opportunities and that they are also vulnerable to higher levels of pollution under those baseline conditions.

3 References

U.S. Environmental Protection Agency. 1972. *Mixing Heights, Wind Speeds, and Potential for the Urban Air Pollution Throughout the Contiguous Unites States*. Prepared by George Holzworth. Research Triangle Park, NC: Office of Air Program, AP-101.

Appendix – Generators

Generator Name	Fuel Type	Resource Owner Name	County	Unit Code
East Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	CL_EWP_30UNITS
Lynchburg Pump Station	Distillate Fuel Oil	NRG Energy Services	Harris	LH_LYN_30UNITS
Northeast Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	DSN_NEWP_10UNITS
Southeast Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	SOE_SEWP_10UNITS
Clear Lake City WWTP	Distillate Fuel Oil	NRG Energy Services	Harris	PHR_CLCWA_5UNITS
Texas City Power Plant	Natural Gas	Calpine Corporation	Galveston	TXCTY_CC1
Freestone Energy Center Block 1	Natural Gas	Calpine Corporation	Freestone	FREC_CC2
W. A. Parish G4	Natural Gas	NRG Energy Services	Fort Bend	WAP_WAP_G4
T. H. Wharton GT54	Natural Gas	NRG Energy Services	Harris	THW_THWGT54
T. H. Wharton GT56	Natural Gas	NRG Energy Services	Harris	THW_THWGT56
Deer Park Energy Center	Natural Gas	Calpine Corporation	Harris	DDPEC_CC1
Texas City Power Plant	Natural Gas	Calpine Corporation	Galveston	TXCTY_CC1
Freestone Energy Center Block 2	Natural Gas	Calpine Corporation	Bosque	FREC_CC2
Bosque Energy Center Block 1	Natural Gas	Calpine Corporation	Bosque	BOSQUESW_CC1
Bosque Energy Center Block 2	Natural Gas	Calpine Corporation	Bosque	BOSQUESW_CC2
Chamon CT1	Natural Gas	Chamon Power LLC	Harris	CHAMON_CTG_0101
Chamon CT2	Natural Gas	Port Comfort Power LLC	Harris	CHAMON_CTG_0301
Port Comfort CT1	Natural Gas	Chamon Power LLC	Calhoun	CALHOUN_UNIT1
Port Comfort CT2	Natural Gas	Port Comfort Power LLC	Calhoun	CALHOUN_UNIT2
Friendswood Energy Genco	Natural Gas	Friendswood Energy Genco LLC	Harris	FEGC_UNIT1

Source: “ERCOT_DOE_202(c)_Exhibit_A_2-17-2021_2100,” ERCOT.

U.S. Department of Energy

National Environmental Policy Act (NEPA)

Implementing Procedures

July 13, 2026

Table of Contents

1.0 Introduction

2.0 Planning and Decision Making

3.0 Implementing NEPA Efficiently

4.0 General

5.0 Establishing, Adopting, and Applying Categorical Exclusions

6.0 Preparing an Environmental Assessment

7.0 Preparing an Environmental Impact Statement

8.0 Definitions

Appendix A: Administrative and Routine Actions Excepted from NEPA Review

Appendix B: Categorical Exclusions Applicable to Specific Agency Actions

Appendix C: Categorical Exclusions Adopted Pursuant to NEPA Section 109

1.0 Introduction

All offices[1] of the Department of Energy (DOE) will use the procedures included herein to comply with the National Environmental Policy Act (NEPA) of 1969, as amended (42 U.S.C. 4331, *et seq*.). These procedures are designed to inform agency decision makers during the decision making process. When DOE is considering a proposed action that is subject to NEPA, these procedures ensure that DOE decision makers are informed, in a timely manner, about the reasonably foreseeable environmental effects of the proposed actions and reasonable alternatives. These procedures recognize that NEPA is a purely procedural statute – it does not dictate DOE's decision – and that DOE has discretion to determine the issues to be considered consistent with the statute.

These procedures describe the process by which DOE determines what actions are subject to NEPA's procedural requirements and the level of required NEPA review; interpret certain key terms used in NEPA; ensure that relevant environmental information is identified and considered early in the process in order to inform decision-making; reduce unnecessary burdens and delays; and implement NEPA's mandates regarding lead and cooperating agency roles, page and time limits, and applicant preparation of environmental documents.

DOE consulted with the Council on Environmental Quality (CEQ) in the development of these procedures for the implementation of NEPA in accord with 42 U.S.C. § 4332(B). DOE will in future consult with CEQ when revising these procedures.

This document provides guidance on DOE's NEPA implementation. This document is not a regulation. Nothing contained in these procedures is intended or should be construed to limit DOE's other authorities or legal responsibilities. These procedures do not, nor are they intended to, confer legal rights, impose legally binding requirements, or impose legal obligations upon DOE, States, federally recognized Indian Tribes, or any member of the public. The sections of these procedures are separate and severable from one another. If any section or portion therein is stayed or determined to be invalid, or the applicability of any section to any person or entity is held invalid, it is DOE's intention that the validity of the remainder of these procedures will not be affected and will continue in effect, along with all applications thereof. DOE retains the discretion to adopt approaches on a case-by-case basis that differ from those described in these procedures where appropriate.

These procedures are consistent with the Supreme Court's decision in *Seven County Infrastructure Coalition et al. v. Eagle County, Colorado*.[2] These procedures represent DOE's understanding that DOE has broad discretion when conducting its reasonable decision making. At a high level, DOE understands that *Seven County* was about the

[1] As used in this document, "DOE offices" refers to all DOE Departmental Elements listed at https://www.directives.doe.gov/references/doe_departmental_elements.

[2] *Seven County Infrastructure Coalition v. Eagle Cnty., Colo.* ("*Seven County*"), 145 S. Ct. 1497 (2025).

separation of powers where agencies may weigh environmental consequences as they reasonably see fit under their governing statute. As made clear in *Seven County*, the central principle of judicial review in NEPA cases is substantial deference to agencies.[3] In addition, NEPA imposes no substantive constraints on any agency's ultimate decision to build, fund, or approve a proposed project. As the Court explained, brevity in a NEPA document should not be mistaken for a lack of detail. Put differently, length is not a prerequisite for a NEPA document to be "detailed" within the meaning of that term as used in the statute or to otherwise be in compliance with NEPA. As the Court additionally explained, Congress in 2023 incorporated deadlines and page limits into the statute which now "strictly prohibit[]" NEPA analysis "from going on endlessly."[4] The review of a NEPA document does not bind DOE's ultimate determination concerning a proposed project. Instead, NEPA documents ensure that agency decision makers are fully informed as to the environmental effects of the proposed action. Ordinarily, DOE NEPA analysis should not consider environmental effects of separate projects, especially those over which DOE does not exercise regulatory authority.

These DOE NEPA implementing procedures, and related guidance and resources, are available on DOE's website at energy.gov/nepa. Questions regarding these procedures and requests to revise these procedures, including to adopt categorical exclusions from another agency, should be addressed to the Office of the General Counsel.

[3] *Id.* at 1511-12.
[4] *Id.* at 1512 n.3.

2.0 Planning and Decision Making

As soon as practical after DOE has identified that it has a proposal, DOE should determine whether compliance with NEPA is required and, if it is, the required level of NEPA review. DOE should integrate the NEPA process with other planning and authorization processes at the earliest reasonable time to avoid delays later in the process, to head off potential conflicts, and to ensure that DOE considers environmental effects in its planning and decisions.

2.1 Determining whether NEPA applies

As an initial matter and serving as an overriding principle, NEPA does not require the agency to weigh environmental consequences in any particular way. The goal of NEPA is to inform an agency decision, not to paralyze it. *See Seven County*, *supra*.

(a) DOE will determine whether NEPA applies to a proposal in accordance with the procedures included in this section. DOE will make this determination on a case-by-case basis.

(b) In determining whether NEPA applies to a proposal, DOE will consider only the action or project at hand.

(c) DOE has determined that the following non-exhaustive list of activities are not subject to NEPA.

(1) NEPA does not apply to response actions taken under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (42 U.S.C. 9601 *et seq*.) because there is a functional equivalency between NEPA and CERCLA.

(2) NEPA does not apply to applications to authorize—
   (i) The import of natural gas; or
   (ii) The export of natural gas to countries with which the United States has a free trade agreement requiring national treatment for trade in natural gas.

   For both types of applications, section 3(c) of the Natural Gas Act (15 U.S.C. 717b) leaves DOE with no discretion whether to approve the application.

(3) NEPA does not apply to applications for a Presidential permit authorizing the construction, connection, operation, or maintenance of facilities for transmission of electric energy between the United States and a foreign country under Executive Order (E.O.) 10485 (18 FR 5397; September 3, 1953), as amended by E.O. 12038 (43 FR 4957; February 7, 1978). DOE's issuance of a Presidential permit is not agency action, but rather delegated Presidential action. Presidential actions are not subject to NEPA or review under the Administrative Procedure Act.

(4) NEPA does not apply to hydroelectric incentive payments made to qualified hydroelectric facilities under section 242 of the Energy Policy Act of 2005 (42 U.S.C 15881). DOE has no discretion in whether to provide payments to a qualified hydroelectric facility, and the payments do not satisfy the definition of major Federal action.

(5) NEPA does not apply to actions that are solely administrative and routine that are undertaken to support the normal conduct of DOE business. While such activities are Federal actions, they are not "major" and therefore not subject to NEPA. These actions were formerly identified as categorical exclusions in appendix A in DOE's regulations. They now represent actions that are excepted from NEPA based on the definition of "major Federal action" in Section 110(10). They have been retained as appendix A for ease of reference and to avoid confusion.

(6) NEPA does not apply to DOE's issuance of emergency Orders pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) because preparing an environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act. As stated at the beginning of this section, NEPA is to inform DOE's decision-making, which is inconsistent with the language and intent of section 202(c), adding further conflict with the statute.

(7) NEPA does not apply to funding DOE provides to local governments, states or Tribes under the Energy Efficiency and Conservation Block Grant Program (42 U.S.C. 17151-58), to funding DOE provides to states under the State Energy Conservation Plan Program (now known as the State Energy Program) (42 U.S.C. 6321-26), or to funding DOE provides to states under the Energy Efficiency Revolving Loan Fund Capitalization Grants Program (42 U.S.C. 18791-92). Under these programs, DOE does not exercise sufficient control and responsibility over the subsequent use of the financial assistance or the effect of the actions due to the statutory restrictions on the recipients' use of DOE's financial assistance. Therefore, DOE's provision of financial assistance under these programs is not a major Federal action subject to NEPA.

(8) NEPA does not apply to rulemaking actions proposed by the Secretary pursuant to section 403(a) of the DOE Act (42 U.S.C. 7173) because such proposals are not final agency action. Section 403(b) specifies that FERC takes "final action" on any rulemaking proposals initiated by the Secretary. NEPA only applies to final agency actions. See 42 U.S.C. 4336(a)(1).

(d) In making a case-by-case determination whether NEPA applies to a program (e.g., implementation of a financial assistance program authorized by Congress) or a particular proposal (e.g., whether to provide financial assistance for a specific project), DOE shall follow criteria included in NEPA and listed below. NEPA does not apply if:

(1) The proposed agency action is not a final agency action within the meaning of such term in chapter 5 of title 5, United States Code (42 U.S.C. 4336(a)(1)) or other relevant statute that also includes a finality requirement. Also see 5 U.S.C. § 704;

(2) The proposed activity or decision is exempted from NEPA by law;

(3) Compliance with NEPA would conflict with the requirements of another provision of law (42 U.S.C. 4336(a)(3));

(4) When Congress has afforded the DOE no discretion over the proposed action.

(5) The proposed action is not a "major Federal action." The terms "major" and "Federal action" each have independent force. NEPA applies only when both of these two criteria are met.

(i) NEPA does not apply to non-Federal actions (I) with no or minimal Federal funding, or (II) with no or minimal Federal involvement where a Federal agency cannot control the outcome of the project (42 U.S.C. § 4336e(10)(B)(i)). In such circumstances, there is no legal requirement nor any practical reason for DOE to conduct a NEPA analysis because DOE could not influence the outcome of its action to address the environmental effects of the proposal. For example, this might include situations where Federal funding constitutes a small percentage of an infrastructure projects overall funding that is provided only to help design an infrastructure project that is otherwise funded from non-Federal sources, because in such situations DOE cannot control the environmental effects of the completed non-Federal action;[5]

(ii) NEPA does not apply to funding assistance solely in the form of general revenue sharing funds which do not provide Federal agency compliance or enforcement responsibility over the subsequent use of such funds (42 U.S.C. § 4336e(10)(B)(ii));

(iii) NEPA does not apply to loans, loan guarantees, or other forms of financial assistance where a Federal agency does not exercise sufficient control and responsibility over the subsequent use of such financial assistance or the effect of the action (42 U.S.C. § 4336e(10)(B)(iii)). For example, financial assistance for non-Federal activities or projects where all physical work has been completed before the applicant seeks funds or reimbursement from DOE (e.g. incentive payments

[5] "The touchstone of major [F]ederal activity constitutes a [F]ederal agency's authority to influence nonfederal activity. 'The [F]ederal agency must possess actual power to control the nonfederal activity.'" *United States v. S. Fla. Water Mgmt. Dist.*, 28 F.3d 1563, 1572 (11th Cir. 1994). A but-for causal relationship is insufficient to make an agency responsible for a particular action under NEPA. See *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 767 (2004). For instance, minimal Federal funding or involvement, which may in a causal sense be a but-for cause of an action, does not by itself convert that action into a Federal action within the meaning of NEPA.

made by DOE to owners or operators of qualified hydroelectric facilities whose project was complete at the time of application to DOE under 42 U.S.C. §15883 (Section 247)) because DOE does not exercise sufficient control and responsibility over the subsequent use of such financial assistance or the effect of the action;

(iv) NEPA does not apply to business loan guarantees provided by the Small Business Administration pursuant to section 7(a) or (b) of the Small Business Act (15 U.S.C. 636(a), (b)), or title V of the Small Business Investment Act of 1958 (15 U.S.C. 695 *et seq*.) (42 U.S.C. § 4336e(10)(B)(iv));

(v) NEPA does not apply to bringing judicial or administrative civil or criminal enforcement actions (42 U.S.C. § 4336e(10)(B)(v)); or

(vi) NEPA does not apply to extraterritorial activities or decisions, which means agency activities or decisions with effects located entirely outside of the jurisdiction of the United States (42 U.S.C. § 4336e(10)(B)(vi)).

(6) The issuance or update of DOE's NEPA procedures is not subject to NEPA review.

2.2 Determining the required level of NEPA review

(a) If DOE determines, as described in section 2.1, that NEPA applies to a proposal, DOE will then determine the required level of NEPA review following the procedures described in this section. DOE will make this determination as soon as practicable after identifying that it has a proposal requiring NEPA review. At all steps in the following process, DOE will consider the proposed action or project at hand and *its* effects.

(b) If DOE has established a categorical exclusion (appendix B) or adopted under section 109 of NEPA another agency's categorical exclusion listed in the other agency's NEPA procedures (42 U.S.C. § 4336(c)) (appendix C), DOE will apply the categorical exclusion(s), following the procedures in chapter 5.

(1) If another agency has already established a categorical exclusion that would apply to the proposed action, DOE will consider whether to rely on that categorical exclusion pursuant to NEPA and the procedures described in section 5.5 so that it can be applied to the proposed action at issue, and to future proposals of that type.

(2) If no relevant categorical exclusion is otherwise available, DOE will consider whether to establish a new categorical exclusion, or revise an existing categorical exclusion, according to the procedures described in section 5.1. If DOE establishes or revises a categorical exclusion, DOE shall then apply the categorical exclusion to the proposed action according to the procedures described in section 5.4.

(c) If DOE cannot apply a categorical exclusion to the proposed action, DOE will evaluate significance of the proposed action's reasonably foreseeable effects consistent with section 3.2, and then will:

(1) If the proposed action is evaluated in a prior NEPA document prepared by DOE or another agency, DOE will consider relying on the existing document, or any pertinent part thereof, and supplementing that document as needed.

(2) If the proposed action is not likely to have a reasonably foreseeable significant effect on the quality of the human environment, or if the significance of the effects of the proposed action is unknown, DOE will prepare an environmental assessment, as described in chapter 6; or

(3) If the proposed action is likely to have a reasonably foreseeable significant effect on the quality of the human environment, DOE will prepare an environmental impact statement, as described in in chapter 7.

(d) DOE may use an early scoping process to help determine the required level of NEPA review. In such a process, DOE should be driven by the need to begin the required NEPA review promptly and should avoid steps that do not demonstrably improve the efficiency of the process. DOE also should remain aware that the schedule for the environmental assessment or environmental impact statement begins once DOE has determined the required level of NEPA review (sections 6.4 and 7.7). DOE should engage any applicant and other parties, as will be beneficial, in the early scoping process. An early scoping process may include, as appropriate to the proposal, steps such as:

(1) Preliminarily identifying the Federal agencies and other parties that will be involved and that have decisions to make related to the proposal; the range of reasonable alternatives and rationale for excluding certain alternatives from detailed analysis; the scope of environmental effects to be analyzed and rationale for excluding certain environmental effects from analysis; and the schedule.

(2) Requesting input from state and local agencies, Tribal governments, industry groups, and the public.

2.3 Applicant and contractor preparation of documents

DOE or an applicant may prepare an environmental assessment or environmental impact statement, including related supplements and supplement analyses, and either may engage a contractor to help prepare such document. An agency-directed contractor is a contractor whose work is supervised and directed by DOE. DOE either hires the agency-directed contractor directly or engages them as part of a third-party contracting arrangement. Under the third-party contracting arrangement, an applicant pays for the

contractor but has no role in directing the work of the contractor. Rather, DOE supervises and directs the contractor's work throughout document preparation.

An applicant-directed contractor is hired and supervised directly by the applicant. DOE provides guidance and direction at particular points throughout document preparation.

2.3.1 DOE responsibilities

DOE is responsible for complying with NEPA and certain requirements in other statutes and regulations (e.g., Endangered Species Act). Certain decisions and actions involved in preparing a NEPA document cannot be delegated to an applicant or contractor. DOE will:

(a) Determine the required level of NEPA review;

(b) Ensure that the scope of analysis and procedural steps are compliant with NEPA and other applicable requirements;

(c) Conduct any government-to-government consultation with Tribal governments and any required consultation with other Federal agencies;

(d) Independently evaluate and take responsibility for the document's contents;

(e) Ensure that the document satisfies all requirements of NEPA and these procedures, including those for page limits and schedule, and determine whether to issue the document, and include a statement in the document confirming that DOE has independently reviewed the document; and

(f) Prepare and issue any finding of no significant impact, record of decision, determination whether additional NEPA review is required, or other decision.

2.3.2 Applicant responsibilities

The applicant for a proposal being analyzed in a NEPA review will:

(a) Provide all information requested by DOE, necessary for the NEPA review, in a timely manner to support the schedule for completing the NEPA review;

(b) Initiate any request to DOE to prepare the NEPA review (as provided by 42 U.S.C. § 4336a(f)) with the application or during the early scoping period prior to DOE's determination of the required level of NEPA review;

(c) Include a statement in the document that it was prepared by the applicant or a contractor paid by the applicant.

(d) DOE may request from an applicant environmental information used to prepare or evaluate the environmental assessment or environmental impact statement. This may include any factual, scientific, or technical information used, developed, or considered by the applicant or applicant-hired contractor in the course of preparing the environmental assessment or environmental impact statement, including any correspondence with DOE or with other parties.

(e) If DOE determines that the applicant-prepared document is likely to be insufficient, DOE may request that the applicant replace its applicant-directed contractor or may take control of completion of the document.

(f) Develop a consolidated administrative record of the information assembled and used to prepare the NEPA document and provide that record to DOE within two weeks of DOE's request.

2.3.3 DOE and applicant coordination during NEPA review

(a) DOE will work with the applicant to define the purpose and need and identify alternatives for detailed analysis that meet the purpose and need.

(b) DOE also will work with the applicant to identify other Federal agencies, state agencies, and Tribes that may have an interest in the proposal and will work with the applicant to identify an appropriate list for notifications and distribution of the document.

(c) DOE will assist applicants and applicant-directed contractors by providing guidance and outlining the types of information required for the preparation of the environmental assessment or environmental impact statement. DOE also may assist in document preparation.

(d) DOE shall develop and modify, as appropriate, a schedule for preparation of the environmental assessment or environmental impact statement that meets the requirements in NEPA and these procedures. The schedule shall provide sufficient time for DOE to review the environmental assessment or environmental impact statement and determine its sufficiency. Major changes to the schedule or related matters will be documented through written correspondence.

2.4 NEPA and rulemaking

(a) Where the proposed action is the promulgation of a rule or regulation, procedures and documentation pursuant to other statutory or Executive Order requirements may satisfy one or more requirements of these procedures. In such circumstances, DOE may substitute the procedures and documentation pursuant to other statutory or Executive Order requirements for the corresponding requirements in these DOE NEPA implementing procedures and need not carry out duplicative procedures or documentation. DOE will

identify which corresponding requirements in these procedures are satisfied and consult with CEQ to confirm such determinations.

(b) Where DOE decides to issue a separate NEPA document in connection with a rulemaking, the NEPA document will normally accompany the proposed rule.

2.5 Lead and cooperating agencies

In many instances, a proposed activity or decision is undertaken in the context which entails activities or decisions undertaken by other Federal agencies (e.g., where multiple Federal authorizations are required with respect to a project sponsor's overall purpose and goal). In such instances, NEPA directs the multiple agencies involved shall determine which of them will be the lead agency pursuant to the criteria identified in NEPA § 107(a)(1)(A), 42 U.S.C. § 4336a(a)(1)(A). When serving as the lead agency, DOE is ultimately responsible for completing the NEPA process. When a joint lead relationship is established pursuant to NEPA § 107(a)(1)(B), 42 U.S.C. § 4336a(a)(1)(B), DOE and the other joint lead agency or agencies are collectively responsible for completing the NEPA process.

3.0 Implementing NEPA Efficiently

DOE will use all available means to improve the efficiency of its implementation of NEPA. DOE will make maximum use of existing analyses to avoid repeating work completed for previous environmental documents or other purposes. DOE also will coordinate with other agencies to make environmental reviews more efficient for all agencies with a decision to make or action to take regarding a proposal. Nothing in this section extends the statutory page limits (sections 6.3 and 7.6) or schedule deadlines (sections 6.4 and 7.7).

3.1 Identifying reasonably foreseeable environmental effects

DOE is responsible under NEPA for analyzing reasonably foreseeable environmental effects (42 U.S.C. 4332(C)(i)) of the proposed action and alternatives. DOE should consider the following factors and the definition of "effects" (chapter 8.0) when identifying reasonably foreseeable effects that require analysis:

(a) DOE shall analyze only those reasonably foreseeable environmental effects that have a reasonably close causal relationship to the proposed agency action and alternatives.

(b) "[W]hen the effects of an agency action arise from a separate project—for example, a possible future project or one that is geographically distinct from the project at hand—NEPA does not require the agency to evaluate the effects of that separate project."[6] In addition, an agency is not required to analyze the effects of projects over which it does not exercise regulatory authority.[7]

3.2 Evaluating significance

Determining whether an environmental effect is significant is a critical part of the NEPA process. Whether an impact rises to the level of "significant" is a matter of DOE's expert judgment. DOE must determine whether environmental effects of a class of actions normally are significant when establishing or revising a categorical exclusion and, in the use of a categorical exclusion whether extraordinary circumstances create significant effects (chapter 5). When a categorical exclusion does not apply to a proposal, DOE

---

[6] *Seven County*, 145 S. Ct. at 1515. The Supreme Court provided the following explanation: "[I]f the project at issue might lead to the construction or increased use of a *separate project*—for example, a housing development that might someday be built near a highway—the agency need not consider the environmental effects *of that separate project*. . . . [T]he separate project breaks the chain of proximate causation between the project at hand and the environmental effects of the separate project." *Id.* at 1515-16 (citing *Public Citizen v. Dep't of Transp.*, 541 U. S. 752, 767 (2004) and *Metropolitan Edison Co. v. People Against Nuclear Energy*, 460 U. S. 766, 774, n. 7 (1983)). "The effects from a separate project may be factually foreseeable, but that does not mean that those effects are relevant to the agency's decisionmaking process or that it is reasonable to hold the agency responsible for those effects. . . . In those circumstances, 'the causal chain is too attenuated.'" *Id.* at 1517 (citing, *inter alia*, *Public Citizen*, 541 U. S. at 766–767 and quoting *Metropolitan Edison*, 460 U. S. at 774). "In other words, there is no 'reasonably close causal relationship' between the project at hand and the environmental effects of those other projects." *Id.* at 1516 (citing *Public Citizen*, 541 U. S. at 767)."

[7] *Id*. at 1516.

considers whether environmental effects are likely to be significant as the central question in deciding whether to prepare an environmental assessment or environmental impact statement (section 2.2). DOE again considers the significance of environmental effects when evaluating changes to a proposed action or new information related to the environmental effects of a proposal (section 3.9). DOE also considers the significance of effects in determining the level of detail to include in an environmental assessment or environmental impact statement.

(a) The analysis of environmental effects should be tailored to the particular proposal including the location. In all cases, DOE's analysis should be "reasonable and reasonably explained,"[8] and the analysis need not run longer than necessary to provide that reasoned explanation.[9] The remainder of this section describes criteria that might factor into DOE's analysis of environmental effects.

(b) DOE may use any reliable data source, and DOE need not undertake new research unless it is essential to a reasoned choice among alternatives and the overall costs and time frame of preparing new information are not unreasonable. (42 U.S.C. 4336(b)(3)) When DOE is evaluating an action's reasonably foreseeable effects on the human environment, and there is incomplete or unavailable information that cannot be obtained at a reasonable cost or the means to obtain it are unknown, DOE should make clear in the relevant environmental document that such information is lacking.

(c) The significance of effects is evaluated in the context of the affected environment (local, regional, or national) and its resources, as appropriate for the specific action and the mechanism or pathway by which the action can result in an environmental effect. Consequently, the environmental document needs a description of the affected environment that is sufficient to support a reasoned explanation of DOE's conclusion regarding the significance of effects. This may be in a standalone section or chapter on the affected environment or integrated into the discussion of environmental effects. In any case, the discussion of the affected environment should not be encyclopedic and need not extend beyond areas associated with reasonably foreseeable environmental effects that have a close causal relationship to the proposed action and alternatives.

(d) In considering whether effects are significant, DOE should consider the following, as appropriate to the specific resource area:

(1) Both short- and long-term effects.

(2) Both beneficial and adverse effects.

---

[8] *Id*. at 1511.

[9] *Id*. at 1512 ("Brevity should not be mistaken for lack of detail. A relatively brief agency explanation can be reasoned and detailed; an EIS need not meander on for hundreds or thousands of pages.").

(3) Effects on public health and safety.

(4) Economic effects.

(5) Effects on the quality of life of the American people.

(e) DOE should evaluate environmental effects in context. In considering short-term effects, for example, DOE should acknowledge that certain adverse effects that occur during construction may be reversible through revegetation or other actions that return the environment to its original condition or to a functioning ecosystem. Such effects are not significant over the long-term, though other effects of construction activities might be. For another example, DOE should acknowledge that facility construction and operation will not be authorized without compliance with applicable laws and other requirements (e.g., DOE orders and technical standards).

3.3 Relying on existing environmental documents

(a) DOE may rely on an environmental assessment, environmental impact statement, or portion thereof, issued by any Federal agency that meets the standards under NEPA and these procedures. (The use of "rely on" is the same concept as "adopt" in prior NEPA practice for environmental assessments and environmental impact statements.) The nature of DOE's reliance on an existing document depends on the relationship of the existing document to DOE's NEPA review of a new or modified proposal.

(1) If the actions analyzed in the original environmental assessment or environmental impact statement and DOE's proposed action are substantially the same, and the analysis in the original document remains sufficient, DOE may republish the relied upon environmental assessment or environmental impact statement to satisfy its responsibilities under NEPA. DOE will add to the republished document a statement that it has confirmed that the original document satisfies DOE's NEPA responsibilities for the new or modified proposal.

(2) If the existing environmental assessment, environmental impact statement, or portion thereof, is only relevant to part of DOE's proposed action, DOE should cite, briefly describe the content and relevance to the environmental document being prepared, and may supplement or make modifications that are necessary to render the relied-upon document, or portion thereof, fit for fulfilling NEPA's analytic requirements for the action at hand.

(3) There is no statutory requirement or otherwise to post a draft EIS for public comment.

3.4 Incorporation by reference

(a) DOE may incorporate material, such as planning studies, technical analyses, or other relevant information, into environmental documents by reference when the effect will be to

cut down on bulk without impeding DOE and public review of the environmental effects of the proposed action or alternatives. When incorporating material by reference, DOE will cite, briefly describe the content and relevance to the environmental document, and make the materials reasonably available by potentially interested parties. If DOE provides an opportunity for public review of the environmental document, DOE also will make any materials incorporated by reference publicly available at the same time. DOE will not use incorporation by reference as a means to evade the statutory page limits (sections 6.3 and 7.6).

(b) Although NEPA itself does not require cost-benefit analysis, DOE may prepare a cost-benefit analysis for a particular proposal. To the extent that this cost-benefit analysis is relevant to any alternatives analysis that DOE is conducting pursuant to NEPA, DOE will incorporate the cost-benefit analysis or append it to the statement to avoid duplication in evaluating the environmental effects. In such cases, the environmental document will discuss the relationship between that analysis and any analyses of unquantified environmental effects, values, and amenities.

3.5 Combining documents

DOE will combine, to the fullest extent practicable, any environmental document with any other agency document to reduce duplication and paperwork. Combining documents does not extend page limits for environmental assessments and environmental impact statements unless another statute applies (sections 6.3 and 7.6).

3.6 Integrating NEPA with other environmental requirements

(a) To the fullest extent possible, DOE will prepare environmental documents concurrently with and integrated with analyses and related surveys and studies required by other Federal statutes.

(b) DOE will combine an environmental document prepared in compliance with NEPA with any other agency document to reduce duplication and paperwork. Thus, DOE may combine an environmental document with related plans, rules, or amendments as a single consolidated document.

(c) If comments on a notice of intent or other aspects of a scoping process identify consultations, permits, or licenses necessary under other environmental laws, the environmental document should contain a section or appendix briefly listing the applicable requirements and how DOE has or will meet them (e.g., permits applied for or received, consultations initiated or concluded).

3.7 Elimination of duplication with State, Tribal, and local procedures

(a) DOE will cooperate with State, Tribal, and local agencies that have a decision or action to make relevant to the environmental effects of the proposal, including laws comparable with NEPA.

(b) To the fullest extent practicable unless specifically prohibited by law, DOE will cooperate with State, Tribal, and local agencies to reduce duplication between NEPA and State, Tribal, and local requirements, including through use by DOE of studies, analysis, and decisions developed by State, Tribal, or local agencies. Such cooperation may include:

(1) Joint planning processes;

(2) Joint environmental research and studies;

(3) Joint public meetings or hearings; and

(4) Joint environmental documents.

3.8 Programmatic environmental documents and tiering

(a) DOE may prepare environmental documents for programmatic Federal actions, such as the adoption of new agency programs. DOE may evaluate the proposal(s) in one of the following ways:

(1) Geographically, including actions occurring in the same general location, such as a DOE site, body of water, region, or metropolitan area.

(2) Generically, including actions that have relevant similarities, such as common timing, effects, alternatives, methods of implementation, media, or subject matter.

(3) By stage of technological development.

(b) Consistent with NEPA § 108, 42 U.S.C. § 4336b, after completing a programmatic environmental assessment or environmental impact statement, DOE may rely on that document for 5 years if there are not substantial new circumstances or information about the significance of adverse effects that bear on the analysis. After 5 years, as long as DOE reevaluates the analysis in the programmatic environmental document and any underlying assumption to ensure reliance on the analysis remains valid and briefly documents its reevaluation and explains why the analysis remains valid considering any new and substantial information or circumstances, DOE may continue to rely on the document.

(c) DOE may, but is not required to, prepare a programmatic environmental document when it does not have a programmatic decision to make. When a programmatic

environmental document is not required, DOE should consider whether a technical report or study would improve the efficiency of future NEPA reviews by providing information on a technology, region, or other subject that can be referenced in future environmental documents.

3.9 Supplements to environmental documents and supplement analyses

(a) DOE is required to prepare supplements to environmental documents only if a major Federal action remains to occur, and:

(1) DOE makes substantial changes to the proposed action that are relevant to environmental concerns; or

(2) DOE decides, in its discretion, that there are substantial new circumstances or information about the significance of the adverse effects that bearing on the proposed action or its effects.

(b) When it is unclear whether or not a supplement to an environmental document is required, DOE may prepare a supplement analysis.

(1) The supplement analysis should discuss the circumstances that are pertinent to deciding whether to prepare a supplement to an environmental document.

(2) The supplement analysis should be brief and need only contain sufficient information for DOE to determine whether:

(i) An existing environmental document should be supplemented;

(ii) A new environmental document should be prepared; or

(iii) No further NEPA documentation is required.

(3) DOE will make the determination and the related supplement analysis available to the public for information.

4.0 General

4.1 Classified, confidential, and otherwise exempt information

(a) Notwithstanding other sections of this part, DOE shall not disclose classified, confidential, or other information that DOE otherwise would not disclose pursuant to the Freedom of Information Act (FOIA) (5 U.S.C. 552) and DOE's regulations implementing the FOIA (10 CFR 1004.10(b)).

(b) To the fullest extent possible, DOE will segregate any information that is exempt from disclosure requirements into an appendix to allow public review of the remainder of the NEPA document.

(c) If exempt information cannot be segregated, or if segregation would leave essentially meaningless material, DOE will withhold the entire NEPA document from the public; however, DOE will prepare the NEPA document and use it in DOE decision-making.

4.2 Appendices

If DOE prepares an appendix, DOE will publish it with the NEPA document. Appendices are to be used for voluminous materials, such as scientific tables, collections of data, statistical calculations, and the like, which substantiate the analysis provided in the environmental assessment. Appendices are not to be used to provide additional substantive analysis, because that would circumvent the congressionally mandated page limits.

Materials may include:

(a) Material prepared in connection with the NEPA document (as distinct from material that is not so prepared and is incorporated by reference (section 3.4)).

(b) Data, brief descriptions of methodology, and other material substantiating any analysis fundamental to the NEPA document, but not analysis. Analysis of environmental effects will be included in the body of the NEPA document.

(c) Comments (or summaries thereof where the response has been exceptionally voluminous) received during the NEPA process and DOE's response to those comments.

4.3 Unique identification numbers

For all environmental documents, DOE will provide a unique identification number for tracking purposes, which DOE will reference on all associated environmental review documents prepared for the proposed agency action and in any database or tracking system for such documents. DOE will coordinate with the CEQ and other Federal agencies to ensure compatibility of such identification numbers across Federal agencies.

4.4 Emergencies

Where emergency circumstances make it necessary to take an action with reasonably foreseeable significant environmental effects without observing the provisions of these procedures, DOE will consult with CEQ about alternative arrangements for compliance with NEPA. In other emergency circumstances, DOE will determine how best to comply with NEPA, including any necessary variance from these DOE NEPA implementing procedures, and notify CEQ about the emergency circumstances and DOE's plan for NEPA compliance.

5.0 Establishing, Adopting, and Applying Categorical Exclusions

Categorical exclusions provide a mechanism to identify types of Federal actions that normally do not have significant environmental effects and for which neither an environmental assessment nor environmental impact statement is normally required. This ensures that resources are not expended conducting environmental analysis of proposals that do not present potential for significant environmental impacts. Categorical exclusions established or adopted by DOE are listed in appendices B–C of these procedures.

(a) All categorical exclusions may be applied by any DOE office. The sectional divisions in appendix B are solely for purposes of organization of that appendix and are not intended to be limiting.

(b) A class of actions includes activities foreseeably necessary to proposals encompassed within the class of actions (such as award of implementing grants and contracts, site preparation, purchase and installation of equipment, and associated transportation activities).

5.1 Establishing and revising categorical exclusions

(a) To establish or revise a categorical exclusion, DOE must determine that the category of actions normally does not significantly affect the quality of the human environment (42 U.S.C. § 4336e(1)). In making this determination, DOE shall:

(1) Develop a written record containing information to substantiate its determination;

(2) Consult with CEQ on its proposed new or revised categorical exclusion, including the written record, for a period not to exceed 30 days prior to providing public notice as described in subparagraph (3); and

(3) Provide public notice in the *Federal Register* of DOE's establishment or revision of any categorical exclusion, including the address of the website where the written record is available (energy.gov/nepa).

(b) If DOE becomes aware of substantial new information about the environmental effects of actions included in an existing categorical exclusion, DOE will determine whether to retain, revise, or remove that categorical exclusion.

(c) DOE will look for opportunities to forego a 30-day consultation process when, consistent with its statutory authority and because of the substantial deference courts give DOE under the *Seven County* decision when doing so is deemed a well-reasoned decision.

5.2 Adopting another agency's categorical exclusion

(a) Consistent with NEPA (42 U.S.C. § 4336c), DOE may adopt a categorical exclusion listed in another agency's NEPA procedures. Once adopted, the categorical exclusion is available for use by all DOE offices. When adopting a categorical exclusion, DOE shall:

(1) Identify the categorical exclusion listed in another agency's NEPA procedures that covers DOE's category of proposed or related actions;

(2) Consult with the agency that established the categorical exclusion to ensure that the proposed adoption of the categorical exclusion is appropriate;

(3) Provide public notification of the categorical exclusion that DOE is adopting, including a brief description of the proposed action or category of proposed actions to which DOE intends to apply the adopted categorical exclusion. DOE shall publish a notice of its adoption on DOE's website at energy.gov/nepa. This notice should explain how DOE intends to use the adopted categorical exclusion (e.g., types of projects, process for considering extraordinary circumstances, and public notice of categorical exclusion determinations), and a brief description of the agencies' consultation; and

(4) DOE will list adopted categorical exclusions in appendix C of these procedures.

(b) If the establishing agency revises a categorical exclusion that DOE has adopted, DOE will determine whether to retain the categorical exclusion as adopted, or to remove the adopted categorical exclusion and adopt the revised categorical exclusion.

(c) After adoption of another agency's categorical exclusion, DOE may decide to follow the process described in section 5.1 to establish it as a DOE categorical exclusion. This could allow, for example, DOE to modify the text of the categorical exclusion to better fit DOE's programs and activities. Otherwise, the categorical exclusion remains as written by the establishing agency.

5.3 Removing a categorical exclusion

(a) To remove a categorical exclusion from DOE's NEPA procedures, DOE will:

(1) Develop a written justification for the removal;

(2) Consult with CEQ on its proposed removal of the categorical exclusion, including the written justification for the removal, for a period not to exceed 30 days prior to providing public notice as described in subparagraph (3); and

(3) Provide public notice of DOE's removal of the categorical exclusion in the *Federal Register* and include the written justification or a link to where that justification is available on DOE's website.

5.4 Applying one or more categorical exclusions to a proposal

(a) Proposed recurring activities to be undertaken during a specified time period, such as routine maintenance activities for a year, may be addressed in a single categorical exclusion determination after considering the potential aggregated impacts.

(b) The following clarifications are provided to assist in the appropriate application of categorical exclusions that employ these terms or phrases:

(1) "Previously disturbed or developed" refers to land that has been changed such that its functioning ecological processes have been and remain altered by human activity. The phrase encompasses areas that have been transformed from natural cover to non-native species or a managed state, including, but not limited to, utility and electric power transmission corridors and rights-of-way, and other areas where active utilities and currently used roads are readily available.

(2) DOE considers terms such as "small" and "small-scale" in the context of the particular proposal, including its proposed location. In assessing whether a proposed action is small, in addition to the actual magnitude of the proposal, DOE considers factors such as industry norms, the relationship of the proposed action to similar types of development in the vicinity of the proposed action, and expected outputs of emissions or waste. When considering the physical size of a proposed facility, for example, DOE would review the surrounding land uses, the scale of the proposed facility relative to existing development, and the capacity of existing roads and other infrastructure to support the proposed action.

(c) To find that a proposal is categorically excluded, DOE shall affirmatively determine the factors listed below. When applying more than one categorical exclusion to a proposal, DOE shall consider these factors for the full scope of the proposal and the collective scope of the categorical exclusions.

(1) The proposal fits within one or more classes of actions listed in appendices B–C of these procedures;

(2) The proposal has not been segmented to meet the definition of a categorical exclusion. Segmentation can occur when a proposal is broken down into small parts in order to avoid the appearance of significance of the total action. However, segmentation does not include proposals that are developed and potentially implemented over multiple phases where each phase results in a decision whether to proceed to the subsequent phase.

(3) There are no extraordinary circumstances related to the proposal that indicate a normally excluded agency action is likely to have a reasonably foreseeable significant adverse effect. It is not the presence of an extraordinary circumstance that precludes application of a categorical exclusion, but rather application of a categorical exclusion is not possible only when DOE concludes that the extraordinary circumstance is likely to cause a reasonably foreseeable significant adverse effect or that DOE does not know the environmental effect of the extraordinary circumstance. DOE or an applicant may modify the proposal to avoid reasonably foreseeable adverse significant effects such that the categorical exclusion would apply. Extraordinary circumstances are unique situations presented by specific proposals, including, but not limited to, uncertain effects or effects involving unique or unknown risks.

(d) DOE will document its determination that one or more categorical exclusions applies to a proposed agency action for any application of a categorical exclusion included in appendices B or C of these procedures.

(e) Categorical exclusion determinations for actions listed in appendix B shall be documented and made available to the public by posting online, generally within two weeks of the determination, unless additional time is needed in order to review and protect classified information, "confidential business information," or other information that DOE would not disclose pursuant to the Freedom of Information Act (FOIA) (5 U.S.C. 552). Posted categorical exclusion determinations shall not disclose classified information, "confidential business information," or other information that DOE would not disclose pursuant to FOIA. (See also section 4.1)

(f) If DOE determines that it cannot apply one or more categorical exclusions to the proposed action, DOE shall prepare an environmental assessment or environmental impact statement, as required (section 2.2(c)).

5.5 Relying on another agency's categorical exclusion determination

DOE may rely on another agency's determination that a categorical exclusion applies to a particular proposed agency action if the agency action covered by that determination and DOE's proposed action are substantially the same.

(a) DOE will coordinate with the agency that made the categorical exclusion determination to ensure that the agency is aware of DOE's intended reliance on its categorical exclusion determination and has had an opportunity to provide input to DOE.

(b) DOE should confirm that reliance on the categorical exclusion determination does not conflict with DOE's NEPA implementing procedures. This would entail consideration of DOE's extraordinary circumstances (section 5.4), integral elements (appendix B), and any relevant categorical exclusions listed in appendix B of these procedures.

(c) DOE will document its reliance on another agency's categorical exclusion determination and post that documentation on DOE's website. That documentation should include the other agency's categorical exclusion determination and a brief explanation of how DOE's proposed action is substantially the same as that of the agency that made the categorical exclusion determination.

6.0 Preparing an Environmental Assessment

If an action is subject to NEPA (section 2.1) and an environmental assessment is the required level of NEPA review (section 2.2), DOE shall prepare an environmental assessment with respect to the proposed agency action following NEPA and the procedures described herein.

6.1 Public engagement in preparation of an environmental assessment

(a) DOE may publish a notice of intent to prepare an environmental assessment or other public notice to request scoping comments on the environmental assessment.

6.2 Contents of an environmental assessment

(a) The scope and level of detail shall be consistent with the narrow purpose of an environmental assessment, i.e., to determine whether any reasonably foreseeable effects of the proposal are likely to be significant and set forth the basis of DOE's finding of no significant impact or determination that an environmental impact statement is required. In preparing the environmental assessment, DOE will focus its analysis on whether the environmental effects of the action or project at hand are significant. As appropriate, DOE will document in the environmental assessment where and how it drew a reasonable and manageable line relating to its consideration of any environmental effects from the action. NEPA directs that environmental assessments are to be "concise" and conform to the page limits (42 U.S.C. § 4336(b)(2) and §4336a(e)(2)) and time limits (42 U.S.C. 4336a(g)) established in the law.

(b) DOE shall include in an environmental assessment a brief discussion of the following topics:

(1) Purpose and need for the proposed action based on DOE's statutory authority. When the proposed action involves a response to an applicant's proposal, the purpose and need shall be informed by the goals of the applicant;

(2) The proposed action, a reasonable number of alternatives to the extent required by NEPA (42 U.S.C. § 4332(2)(F) and 4332(2)(H)), and no action alternative (which may be encompassed within the discussion of the affected environment);

(3) An explanation why particular environmental effects would not result in significant impact and, thus, are not further analyzed in the environmental assessment (section 3.2); and

(4) The reasonably foreseeable effects of the proposed agency action and the alternatives evaluated sufficiently to determine whether any of the effects are likely to be significant and whether any significant effects can be made non-significant through mitigation.

6.3 Page limits

(a) DOE shall conform to page limits established in NEPA (42 U.S.C. § 4336(e)(2)) and as described in this section.

(1) The text of an environmental assessment is strictly prohibited from exceeding 75 pages, not including citations or appendices. NEPA does not provide agencies with the authority or a mechanism to exceed this page limit.

(2) Appendices are to be used for voluminous materials, such as scientific tables, collections of data, statistical calculations, and the like, which substantiate the analysis provided in the environmental assessment. Appendices are not to be used to provide additional substantive analysis, because that would circumvent the congressionally mandated page limits.

(3) Environmental assessments shall be formatted for an 8.5”x11” page with one-inch margins using a 12-point proportionally spaced font, single spaced. Footnotes may be in 10-point font. Such size restrictions do not apply to explanatory maps, diagrams, graphs, tables, and other means of graphically displaying quantitative or geospatial information. When an item of graphical material is larger than 8.5”x11”, each such item shall count as one page.

(4) Certification Related to Page Limits. The breadth and depth of analysis in an environmental assessment shall be tailored to ensure that the environmental analysis does not exceed this 75-page limit. As part of the finalization of the environmental assessment, a responsible official shall certify (and the certification shall be incorporated into the environmental assessment) that DOE has considered the factors mandated by NEPA; that the environmental assessment represents DOE’s good-faith effort to prioritize documentation of the most important considerations required by the statute within the Congressionally mandated page limits; that this prioritization reflects DOE’s expert judgment; and that any considerations addressed briefly or left unaddressed were, in DOE’s judgment, comparatively not of a substantive nature that meaningfully informed the consideration of environmental effects and the resulting decision.

(5) DOE recognizes that NEPA imposes no substantive environmental obligations or restrictions because it is a purely procedural statute that requires an agency to prepare a report, as stated in the *Seven County* decision, *supra*. DOE is encouraged to maximize its substantial discretion to not only stay within the page limits but also to limit lengthy appendices.

6.4 Deadlines

(a) As the Supreme Court has repeatedly held, NEPA is governed by a "rule of reason." Congress supplied the measure of that reason in the 2003 revision of NEPA by setting the deadlines in NEPA 107(g), 42 U.S.C. 4336a(g). These deadlines indicate Congress's determination that an agency has presumptively spent a reasonable amount of time on analysis and the document should issue, absent very unusual circumstances. In such circumstances, an extension will be given only for such time as is *necessary* to complete the analysis.

To effectively support decision making for proposals initiated within DOE and for proposals brought to DOE by applicants for financial assistance or other authorization, NEPA must be implemented through predictable and reasonable timelines.[10] Thus, NEPA directs that Federal agencies will complete each environmental assessment not later than the date that is one year after the sooner of:

(1) The date on which DOE determines that NEPA requires the preparation of an environmental assessment with respect to the proposal;

(2) The date on which DOE notifies the applicant that the application to establish a right-of-way for the proposal is complete; and

(3) The date on which DOE issues a notice of intent to prepare the environmental assessment for the proposal. (42 U.S.C. § 4336a(g)(1)(B))

(b) DOE should document the start date of each environmental assessment in writing and approved by the DOE official responsible for completing the environmental assessment on schedule. This documentation will assist DOE in tracking the schedule and preparing the report to congressional committees required by NEPA (42 U.S.C. 4336a(h)). The start date normally will be the date that DOE determines that preparation of an environmental assessment is required (option (a)(1) above). DOE does not receive applications to establish a right-of-way (though this option might be relevant in circumstances when DOE is participating with another Federal agency). If DOE were to issue a notice of intent to prepare an environmental assessment, that normally would follow DOE's determination that an environmental assessment is required.

(c) If DOE determines it is not able to meet the one-year deadline, it must consult with the applicant, if any (42 U.S.C. § 4336a(g)(2)). After such consultation, if needed, DOE may establish a new deadline that provides only so much additional time as is necessary to complete the environmental assessment. The deadline extension should be approved, in

[10] "Time and resources are simply too limited for us to believe that Congress intended" consideration under NEPA to extend indefinitely. *Metro. Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, 776 (1983) (citing Vermont *Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519, 551 (1978)).

writing, by the DOE official responsible for completing the environmental assessment on schedule. This documentation will assist DOE in tracking the schedule and preparing the report to congressional committees required by NEPA (42 U.S.C. 4336a(h)).

Cause for setting a new deadline is only established if the EA is not sufficiently researched and written to support a FONSI or NOI to prepare an EIS. The announcement of the new deadline shall specify the reason why the environmental assessment was not able to be completed under the statutory deadline.

(d) DOE shall calculate environmental assessment schedules from the applicable start date to issuance of the environmental assessment.

(e) DOE should publish the environmental assessment, at the latest, on the day the deadline elapses, in as substantially complete form as is possible.

(f) Certification Related to Deadline. When the environmental assessment is published, a responsible DOE official should certify (and the certification will be incorporated into the environmental assessment) that the resulting environmental assessment represents DOE's good-faith effort to fulfill NEPA's requirements within the Congressional timeline; that such effort is substantially complete; that, in DOE's expert opinion, the analysis contained therein is adequate to inform and reasonably explain DOE's final decision regarding the proposed action.

6.5 Findings of no significant impact

(a) DOE shall prepare a finding of no significant impact if DOE determines, based on the environmental assessment, not to prepare an environmental impact statement because the proposed action or project at hand will not have significant effects. The finding of no significant impact shall:

(1) Include the environmental assessment or incorporate it by reference;

(2) Document the reasons why DOE has determined that the selected alternative will not have a significant effect on the quality of the human environment;

(3) State the authority for any mitigation that DOE has adopted and any applicable monitoring or enforcement provisions. If DOE finds no significant effects based on mitigation, the mitigated finding of no significant impact shall state any mitigation requirements enforceable by the agency (e.g., through conditions on awards or contractor requirements) or voluntary mitigation commitments that will be undertaken to avoid significant effects;

(4) Identify any other documents related to the finding of no significant impact; and

(5) State that an environmental impact statement will not be prepared, concluding the NEPA process for that action.

(b) DOE shall make each environmental assessment and finding of no significant impact available to the public by posting on its website.

7.0 Preparing an Environmental Impact Statement

If an action is subject to NEPA (section 2.1) and an environmental impact statement is the required level of NEPA review (section 2.2), DOE shall prepare an environmental impact statement with respect to the proposed agency action following NEPA and the procedures described herein.

7.1 Notice of intent and scoping

(a) As a preliminary step to determining whether, in connection with a proposal that is not excluded pursuant to a categorical exclusion, DOE will prepare an environmental assessment or an environmental impact, DOE will determine and document the scope of the project at hand.

(b) DOE should publish a concise notice of intent to prepare an environmental impact statement as soon as practicable after determining that an environmental impact statement is required for a proposed agency action. This is important to ensure timely decision making and because the two-year deadline for completing the environmental impact statement will typically be measured from the date that DOE determined that an environmental impact statement is required (section 7.7).

(c) The notice of intent shall include a request for public comment on alternatives or effects and on relevant information, studies, or analyses with respect to the proposed agency action (42 U.S.C. § 4336a(c)). The notice of intent also should include information to inform the public in preparing comments, such as:

(1) The purpose and need for the proposed action (section 7.2);

(2) A preliminary description of the proposed action and reasonable alternatives expected to be analyzed;

(3) A brief summary of environmental effects that DOE expects to analyze and identification of those environmental effects that DOE anticipates are not likely to be significant and, therefore, not analyzed in detail;

(4) Anticipated permits and other authorizations required for the proposed action and reasonable alternatives to proceed (e.g., connected actions);

(5) A schedule for the decision-making process that is consistent with the deadlines for an environmental impact statement established in NEPA. There is no statutory requirement or otherwise to post a draft EIS for public comment;

(6) A description of planned opportunities for engagement by Tribes, the public, and other parties, including any scoping meeting(s), the end date for the public comment period,

and whether DOE anticipates releasing a draft environmental impact statement or related materials;

(7) Identification of any cooperating and participating agencies, and any information that such agencies require in the notice to facilitate their decisions or authorizations; and

(8) Contact information for a person within DOE who can answer questions about the proposed action and the environmental impact statement.

7.2 Purpose and need

DOE shall include in the environmental impact statement a brief summary of the underlying of purpose and need for the proposed agency action based on DOE's statutory authority. (42 U.S.C. 4336(d)) When the proposed agency action concerns DOE's duty to act on an application for authorization of financial assistance or other purposes, the purpose and need for the proposed agency action should be informed by the goals of the applicant.

7.3 Alternatives in an environmental impact statement

(a) NEPA requires that an environmental impact statement include "a reasonable range of alternatives to the proposed agency action, including an analysis of any negative environmental impacts of not implementing the proposed agency action in the case of a no action alternative, that are technically and economically feasible, and meet the purpose and need of the proposal." (42 U.S.C. 4332(C)(iii)) Accordingly, in all environmental impact statements, DOE shall analyze:

(1) the proposed action;

(2) a reasonable range of technically and economically feasible alternatives that meet the purpose and need of the proposal and, where applicable, meet the goals of the applicant; and

(3) no action, which may be limited to an analysis of negative environmental effects of not implementing the proposed action.

(b) DOE shall identify the reasonable range of alternatives on a project-by-project basis. To be included within the reasonable range of alternatives, the evaluation of that alternative should contribute to DOE's decision making.

(c) For any alternative that DOE considered but determined not to analyze in detail, DOE will provide a brief explanation of why the alternative was not included among the reasonable range of alternatives in the environmental impact statement. DOE should include this explanation in the environmental impact statement.

7.4 Contents of an environmental impact statement

(a) An environmental impact statement shall demonstrate DOE's consideration of:

(1) reasonably foreseeable environmental effects of the proposed agency action;

(2) any reasonably foreseeable adverse environmental effects which cannot be avoided should the proposal be implemented;

(3) a reasonable range of alternatives to the proposed agency action, including an analysis of any adverse environmental impacts of not implementing the proposed agency action in the case of a no action alternative, that are technically and economically feasible, and meet the purpose and need of the proposal;

(4) the relationship between local short-term impacts on the human environment and the maintenance and enhancement of long-term productivity;

(5) any irreversible and irretrievable commitments of Federal resources which would be involved in the proposed agency action should it be implemented; and

(6) any means identified to mitigate adverse environmental effects of the proposed action. DOE is mindful that in this respect NEPA itself does not require or authorize DOE to impose any mitigation measures.

(b) In preparing the environmental impact statement, DOE will focus its analysis on whether the environmental effects of the action or project at hand are significant. DOE will document in the environmental impact statement where and how it drew a reasonable and manageable line relating to its consideration of any environmental effects from the action or project at hand that extend outside the geographical territory of the project or might materialize later in time.

(c) Environmental impact statements should discuss effects in proportion to their significance. With respect to issues that are not substantive and do not meaningfully inform the consideration of environmental effects and the resulting decision on how to proceed, there should be no more than the briefest possible discussion to explain why those issues are not substantive and therefore not amenable to further analysis. Environmental impact statements should be analytic, concise, and no longer than necessary to comply with NEPA in light of the congressionally mandated page limits and deadlines.

7.5 Receipt of comments

During the process of preparing an environmental impact statement, DOE will seek the comments of any Federal agency that has jurisdiction by law or special expertise with respect to any environmental impact involved. As appropriate, DOE will seek the

comments of State, Tribal, and local agencies that may be affected by the proposed action. In addition, DOE may seek comments if it believes such comments will aid in discharging its duties under NEPA.

7.6 Page limits

(a) The text of an environmental impact statement shall not exceed 150 pages, not including citations or appendices, unless the proposal is of extraordinary complexity, in which case the text is strictly prohibited from exceeding 300 pages, not including any citations or appendices (42 U.S.C. 4336(e)(1)). NEPA provides no method for an agency to extend the latter page limit.

(b) Environmental impact statements should be formatted for an 8.5”x11” page with one-inch margins using a word processor with 12-point proportionally spaced font, single spaced. Footnotes may be in 10-point font. Such size restrictions do not apply to explanatory maps, diagrams, graphs, tables, and other means of graphically displaying quantitative or geospatial information, although pages containing such material do count towards the page limit. When an item of graphical material is larger than 8.5”x11,” each such item shall count as one page.

(c) Certification Related to Page Limits. The breadth and depth of analysis in an environmental impact statement shall be tailored to ensure that the environmental impact statement does not exceed these page limits. In this regard, as part of the finalization of the environmental impact statement, a responsible official should certify that DOE has considered the factors mandated by NEPA; that the environmental impact statement represents DOE’s good-faith effort to prioritize documentation of the most important considerations required by the statute within the Congressionally mandated page limits; that this prioritization reflects DOE’s expert judgment; and that any considerations addressed briefly or left unaddressed were, in DOE’s judgment, comparatively unimportant or frivolous.

7.7 Deadlines

(a) As the Supreme Court has repeatedly held, NEPA is governed by a “rule of reason.” Congress supplied the measure of that reason in the 2023 revision of NEPA by setting the deadlines in NEPA 107(6), 42 U.S.C. 4336a(g). These deadlines indicate Congress’s determination that an agency, working within Congress’s allocation of resources, has presumptively spent a reasonable amount of time on analysis and the document should issue, absent very unusual circumstances. In such circumstances, an extension will be given only for such time as is necessary to complete the analysis.

To effectively support decision making for proposals initiated within DOE and for proposals brought to DOE by applicants for financial assistance or other authorization, NEPA must be

implemented through a predictable and reasonable schedule.[11] Thus, NEPA directs that Federal agencies will complete each environmental impact statement not later than the date that is two years after the earlier of:

(1) The date on which DOE determines that NEPA requires the preparation of an environmental impact statement with respect to the proposal;

(2) The date on which DOE notifies the applicant that the application to establish a right-of-way for the proposal is complete; and

(3) The date on which DOE issues a notice of intent to prepare the environmental impact statement for the proposal. (42 U.S.C. § 4336a(g)(1)(A))

(b) DOE should document the start date of each environmental impact statement in writing and approved by the DOE official responsible for completing the environmental impact statement on schedule. This documentation will assist DOE in tracking the schedule and preparing the report to congressional committees required by NEPA (42 U.S.C. 4336a(h)). The start date normally will be the date that DOE determines that preparation of an environmental impact statement is required (option (a)(1) above). DOE does not receive applications to establish a right-of-way (though this option might be relevant in circumstances when DOE is participating with another Federal agency). If DOE were to issue a notice of intent to prepare an environmental impact statement, that normally would follow DOE's determination that an environmental impact statement is required.

(c) DOE shall calculate environmental impact statement schedules from the applicable start date to the date of publication by the U.S. Environmental Protection Agency in the *Federal Register* of a notice of availability of the environmental impact statement as the end date. Where DOE has prepared an environmental assessment that results in a decision to prepare an EIS, DOE will use the start date for the environmental assessment as the start date for the EIS unless it exercises its discretion to determine otherwise by direction of DOE leadership.

(d) DOE will strive to publish the EIS, complete, as soon as possible. DOE should publish the environmental impact statement, at the latest, on the day the deadline elapses, in as substantially complete form as is possible.

(e) If DOE determines it is not able to meet the two-year deadline, it must consult with the applicant, if any (42 U.S.C. § 4336a(g)(2)). After such consultation, if needed, DOE may establish a new deadline that provides only so much additional time as is necessary to complete the environmental impact statement. The deadline extension should be

[11] "Time and resources are simply too limited for us to believe that Congress intended" consideration under NEPA to extend indefinitely. *Metro. Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, 776 (1983) (citing Vermont *Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519, 551 (1978)).

approved, in writing, by the DOE official responsible for completing the environmental impact statement on schedule. This documentation will assist DOE in tracking the schedule and preparing the report to congressional committees required by NEPA (42 U.S.C. 4336a(h)).

Cause for setting a new deadline is only established if the environmental impact statement is not sufficiently developed to support a Record of Decision. The announcement of the new deadline shall specify the reason why the environmental impact statement was not able to be completed under the statutory deadline.

(f) Certification Related to Deadlines. When the environmental impact statement is published, a responsible DOE official should certify (and the certification will be incorporated into the environmental impact statement) that the resulting environmental impact statement represents DOE's good faith effort to fulfill NEPA's requirements within the Congressional timeline; that such effort is substantially complete; and that, in DOE's expert opinion, it has thoroughly considered the factors mandated by NEPA; and that in DOE's judgement the analysis contained therein is adequate to inform and reasonably explain DOE's final decision regarding the proposed Federal action.

7.8 Publication of an environmental impact statement

It is the policy of DOE to undertake no obligation beyond those required by NEPA. in the creation and publication of an EIS. NEPA should not unnecessarily obstruct projects, create inefficiencies, or add costs that are not mandated by statute.

(a) DOE shall file each environmental impact statement together with comments and responses it solicited with the U.S. Environmental Protection Agency (EPA), Office of Federal Activities, following EPA's filing guidance (https://www.epa.gov/nepa/environmental-impact-statement-filing-guidance). EPA will include the EIS in its weekly notice of availability published in the *Federal Register*.

(b) DOE shall publish the entire environmental impact statement, including any appendices, and DOE's decision by posting it on DOE's website consistent with NEPA (42 U.S.C. 4332(c)). During the process of preparing the environmental impact statement, DOE also may publish on its website or a website developed by a contractor such draft materials as in DOE's judgment may assist in fulfilling its responsibilities under NEPA and these procedures.

7.9 Decision

(a) DOE's decision shall come from analyzed alternatives.

(b) DOE's decision may be described in a record of decision or incorporated into a separate decision document (e.g., a DOE order).

(c) DOE's decision may be made concurrently with or at any time after the environmental impact statement is made publicly available.

8.0 Definitions

As used in these implementing procedures, terms have the meanings provided in NEPA § 111, 42 U.S.C. § 4336e. In addition:

Appendix means additional matter placed at the end of a NEPA document or in a separate volume that provides support for analysis in the NEPA document but does not include analysis of environmental effects.

Applicant means a non-Federal entity requesting financial assistance or other authorization from DOE. This has the same meaning as "project sponsor" as used in NEPA.

Authorization means any license, permit, approval, finding, determination, or other administrative decision issued by an agency that is required or authorized under Federal law in order to implement a proposed action.

CEQ means the Council on Environmental Quality.

CERCLA-excluded petroleum and natural gas products means petroleum, including crude oil or any fraction thereof, that is not otherwise specifically listed or designated as a hazardous substance under section 101(14) of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (42 U.S.C. 9601.101(14)) and natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel or of pipeline quality (or mixtures of natural gas and such synthetic gas).

Connected action means a separate Federal action within the authority of DOE that is closely related to the proposed agency action and should be addressed in a single environmental document because the proposed agency action::

(i) Automatically triggers the separate Federal action, which independently would require the preparation of additional environmental documents;

(ii) Cannot proceed unless the separate Federal action is taken previously or simultaneously; or

(iii) Is an interdependent part of a larger Federal action that includes a separate Federal action, which mutually depend on the larger Federal action for their justification.

Contaminant means a substance identified within the definition of contaminant in section 101(33) of CERCLA (42 U.S.C. 9601.101(33)).

Day means a calendar day.

DOE means the U.S. Department of Energy.

Early scoping means the period after identifying that a proposal requires NEPA review (section 2.1) and prior to DOE determining the required level of NEPA review (section 2.2). DOE may conduct this process internally and may involve external parties at its discretion.

Effects or *impacts* means changes to the human environment from the proposed action or alternatives that are reasonably foreseeable and have a reasonably close causal relationship to the proposed action or alternatives. The terms *effects* and *impacts* are used interchangeably.

(1) Effects include ecological (such as the effects on natural resources and on the components, structures, and functioning of affected ecosystems), aesthetic, historic, cultural, economic (such as the effects on employment), social, or health effects. Effects appropriate for analysis under NEPA may be either beneficial or adverse, or both, with respect to these values.

(2) A "but for" causal relationship is insufficient to make an agency responsible for a particular effect under NEPA. Effects should generally not be considered if they are remote in time, geographically remote, or the product of a lengthy causal chain. Effects do not include those effects that the agency has no ability to prevent due to the limits of its regulatory authority, or that would occur regardless of the proposed action, or that would need to be initiated by a third party.

Hazardous substance means a substance identified within the definition of hazardous substances in section 101(14) of CERCLA (42 U.S.C. 9601.101(14)). Radionuclides are hazardous substances through their listing under section 112 of the Clean Air Act (42 U.S.C. 7412) (40 CFR part 61, subpart H).

Human environment means comprehensively the natural and physical environment and the relationship of present and future generations of Americans with that environment.

Interim action means an action concerning a proposal that is the subject of an ongoing NEPA review and that DOE proposes to take before that NEPA review is complete, and that is permissible under NEPA.

Jurisdiction by law means agency authority to approve, veto, or finance all or part of the proposal.

Mitigation means measures that avoid, minimize, or compensate for effects caused by a proposed action or alternatives as described in an environmental document or record of decision and that have a nexus to those effects. NEPA does not mandate the form or adoption of any mitigation. Mitigation includes:

(1) Avoiding the impact altogether by not taking a certain action or parts of an action.

(2) Minimizing effects by limiting the degree or magnitude of the action and its implementation.

(3) Rectifying the impact by repairing, rehabilitating, or restoring the affected environment.

(4) Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.

(5) Compensating for the impact by replacing or providing substitute resources or environments.

NEPA means the National Environmental Policy Act, as amended (42 U.S.C. § 4321, *et seq*.).

NEPA document means a DOE notice of intent (NOI), environmental impact statement (EIS), record of decision (ROD), environmental assessment (EA), finding of no significant impact (FONSI), supplement analysis (SA), categorical exclusion (CX) determination, or any other document prepared pursuant to a requirement of NEPA or these procedures.

NEPA process or *NEPA review* means all measures necessary for compliance with the requirements of NEPA.

Notice of Availability means a formal notice, published by EPA in the *Federal Register*, that announces the issuance and public availability of a draft or final EIS. A DOE Notice of Availability is an optional notice used to provide information to the public that may be published in the *Federal Register* or otherwise made publicly available.

Notice of early scoping means an optional public notice that DOE has identified a proposed action and is soliciting input to help DOE determine the scope of analysis and appropriate type of NEPA review.

Notice of intent means a public notice that an agency will prepare and consider an environmental document.

Pollutant means a substance identified within the definition of pollutant in section 101(33) of CERCLA (42 U.S.C.9601.101(33)).

Program means a sequence of connected or related DOE actions or projects.

Project means a specific DOE undertaking including actions approved by permit or other regulatory decision as well as Federal and federally assisted activities, which may include design, construction, and operation of an individual facility; research, development, demonstration, and testing for a process or product; financial assistance or funding for a facility, process, or product; or similar activities.

Proposed agency action or *proposed action* means the decision to be made by DOE or another Federal agency. For example, in common usage, an applicant's proposal might be to construct and operate a facility, and DOE's proposed action might be to provide financial assistance to the applicant for that proposal.

Publish and *publication* mean methods used by DOE to efficiently and effectively make environmental documents and information available for review by interested persons, including electronic publication.

Reasonable alternatives means a reasonable range of alternatives that are technically and economically feasible, meet the purpose and need for the proposed action, and, where applicable, meet the goals of the applicant.

Reasonably foreseeable means sufficiently likely to occur such that a person of ordinary prudence would take it into account in reaching a decision.

Related action means an action undertaken by an agency, *e.g.*, a permitting action, some other type of authorization action, an analysis required by statute, or the like, that bears a relationship to other actions undertaken by other agencies relevant to NEPA, *e.g.*, that a set of related actions are all related to one overarching project.

ROD means a Record of Decision.

Scope consists of the range of actions, alternatives, and effects to be considered in an environmental document. The scope of an individual statement may depend on its relationships to other statements.

Scoping means the process, whether internal or public, to identify the scope of the NEPA review.

Site-wide NEPA document means a broad-scope environmental impact statement or environmental assessment that identifies and assesses the impacts of ongoing and reasonably foreseeable future actions at a DOE site; it may also refer to an associated NEPA document, such as a notice of intent, record of decision, or finding of no significant impact.

Special expertise means statutory responsibility, agency mission, or related program experience. (42 U.S.C. § 4336e(13))

Substantially the same means that DOE and another agency are proposing actions related to the same project. For example, one agency has permitting authority and the other agency proposes to provide financial support for the same project. For another example, an agency has requested DOE assistance to work on a site, facility, or land managed by or under the jurisdiction of the requesting agency.

Supplement Analysis means a DOE document used to determine whether a supplemental EIS should be prepared (section 3.9), or to support a decision to prepare a new EIS.

Supplemental EIS means an EIS prepared to supplement a prior EIS (section 3.9).

The Secretary means the Secretary of Energy.

Tiering refers to the coverage of general matters in broader environmental impact statements or environmental assessments (such as national program or policy statements) with subsequent narrower statements or environmental analyses (such as regional or basin-wide program statements or ultimately site-specific statements) incorporating by reference the general discussions and concentrating solely on the issues specific to the statement subsequently prepared.

Appendix A: Administrative and Routine Actions Excepted from NEPA Review

[These actions were formerly identified as categorical exclusions in appendix A of subpart D in DOE's regulations. They now represent actions that are excepted from NEPA based on the definition of "major Federal action" in Section 110(10). They have been retained as appendix A for ease of reference and to avoid confusion.]

Table of Contents

A1 Routine DOE business actions
A2 Clarifying or administrative contract actions
A3 Certain actions by Office of Hearings and Appeals
A4 Interpretations and rulings for existing regulations
A5 Interpretive rulemakings with no change in environmental effect
A6 Procedural rulemakings
A7 [Reserved]
A8 Awards of certain contracts
A9 Information gathering, analysis, and dissemination
A10 Reports and recommendations on non-DOE legislation
A11 Technical advice and assistance to organizations
A12 Emergency preparedness planning
A13 Procedural documents
A14 Approval of technical exchange arrangements
A15 International agreements for energy research and development

A1 Routine DOE business actions

Routine actions necessary to support the normal conduct of DOE business limited to administrative, financial, and personnel actions.

A2 Clarifying or administrative contract actions

Contract interpretations, amendments, and modifications that are clarifying or administrative in nature.

A3 Certain actions by Office of Hearings and Appeals

Adjustments, exceptions, exemptions, appeals and stays, modifications, or rescissions of orders issued by the Office of Hearings and Appeals.

A4 Interpretations and rulings for existing regulations

Interpretations and rulings with respect to existing regulations, or modifications or rescissions of such interpretations and rulings.

A5 Interpretive rulemakings with no change in environmental effect

Rulemakings interpreting or amending an existing rule or regulation that does not change the environmental effect of the rule or regulation being amended.

A6 Procedural rulemakings

Rulemakings that are strictly procedural, including, but not limited to, rulemaking (under 48 CFR chapter 9) establishing procedures for technical and pricing proposals and establishing contract clauses and contracting practices for the purchase of goods and services, and rulemaking (under 10 CFR part 600) establishing application and review procedures for, and administration, audit, and closeout of, grants and cooperative agreements.

A7 [Reserved]

A8 Awards of certain contracts

Awards of contracts for technical support services, management and operation of a government-owned facility, and personal services.

A9 Information gathering, analysis, and dissemination

Information gathering (including, but not limited to, literature surveys, inventories, site visits, and audits), data analysis (including, but not limited to, computer modeling), document preparation (including, but not limited to, conceptual design, feasibility studies, and analytical energy supply and demand studies), and information dissemination (including, but not limited to, document publication and distribution, and classroom training and informational programs), but not including site characterization or environmental monitoring. (See also B3.1 of appendix B to these procedures.)

A10 Reports and recommendations on non-DOE legislation

Reports and recommendations on legislation or rulemaking that are not proposed by DOE.

A11 Technical advice and assistance to organizations

Technical advice and planning assistance to international, national, state, and local organizations.

A12 Emergency preparedness planning

Emergency preparedness planning activities, including, but not limited to, the designation of onsite evacuation routes.

A13 Procedural documents

Administrative, organizational, or procedural Policies, Orders, Notices, Manuals, and Guides.

A14 Approval of technical exchange arrangements

Approval of technical exchange arrangements for information, data, or personnel with other countries or international organizations (including, but not limited to, assistance in identifying and analyzing another country's energy resources, needs and options).

A15 International agreements for energy research and development

Approval of DOE participation in international “umbrella” agreements for cooperation in energy research and development activities that would not commit the U.S. to any specific projects or activities.

Appendix B: Categorical Exclusions Applicable to Specific Agency Actions

[These categorical exclusions are copied from DOE's existing regulations.]

Table of Contents

B. Conditions that Are Integral Elements of the Classes of Actions in Appendix B

B1. Categorical Exclusions Applicable to Facility Operation

B1.1 Changing rates and prices
B1.2 Training exercises and simulations
B1.3 Routine maintenance
B1.4 Air conditioning systems for existing equipment
B1.5 Existing steam plants and cooling water systems
B1.6 Tanks and equipment to control runoff and spills
B1.7 Electronic equipment
B1.8 Screened water intake and outflow structures
B1.9 Airway safety markings and painting
B1.10 Onsite storage of activated material
B1.11 Fencing
B1.12 Detonation or burning of explosives or propellants after testing
B1.13 Pathways, short access roads, and rail lines
B1.14 Refueling of nuclear reactors
B1.15 Support buildings
B1.16 Asbestos removal
B1.17 Polychlorinated biphenyl removal
B1.18 Water supply wells
B1.19 Microwave, meteorological, and radio towers
B1.20 Protection of cultural resources, fish and wildlife habitat
B1.21 Noise abatement
B1.22 Relocation of buildings
B1.23 Demolition and disposal of buildings
B1.24 Property transfers
B1.25 Real property transfers for cultural resources protection, habitat preservation, and wildlife management
B1.26 Small water treatment facilities
B1.27 Disconnection of utilities
B1.28 Placing a facility in an environmentally safe condition
B1.29 Disposal facilities for construction and demolition waste
B1.30 Transfer actions
B1.31 Installation or relocation of machinery and equipment
B1.32 Traffic flow adjustments
B1.33 Stormwater runoff control

B1.34 Lead-based paint containment, removal, and disposal
B1.35 Drop-off, collection, and transfer facilities for recyclable materials
B1.36 Determinations of excess real property

B2. Categorical Exclusions Applicable to Safety and Health

B2.1 Workplace enhancements
B2.2 Building and equipment instrumentation
B2.3 Personnel safety and health equipment
B2.4 Equipment qualification
B2.5 Facility safety and environmental improvements
B2.6 Recovery of radioactive sealed sources

B3. Categorical Exclusions Applicable to Site Characterization, Monitoring, and General Research

B3.1 Site characterization and environmental monitoring
B3.2 Aviation activities
B3.3 Research related to conservation of fish, wildlife, and cultural resources
B3.4 Transport packaging tests for radioactive or hazardous material
B3.5 Tank car tests
B3.6 Small-scale research and development, laboratory operations, and pilot projects
B3.7 New terrestrial infill exploratory and experimental wells
B3.8 Outdoor terrestrial ecological and environmental research
B3.9 Projects to reduce emissions and waste generation
B3.10 Particle accelerators
B3.11 Outdoor tests and experiments on materials and equipment components
B3.12 Microbiological and biomedical facilities
B3.13 Magnetic fusion experiments
B3.14 Small-scale educational facilities
B3.15 Small-scale indoor research and development projects using nanoscale materials
B3.16 Research activities in aquatic environments

B4. Categorical Exclusions Applicable to Electric Power and Transmission

B4.1 Contracts, policies, and marketing and allocation plans for electric power
B4.2 Export of electric energy
B4.3 Electric power marketing rate changes
B4.4 Power marketing services and activities
B4.5 Temporary adjustments to river operations
B4.6 Additions and modifications to transmission facilities
B4.7 Fiber optic cable
B4.8 Electricity transmission agreements
B4.9 Multiple use of powerline rights-of-way

B4.10 Removal of electric transmission facilities
B4.11 Electric power substations and interconnection facilities
B4.12 Construction of powerlines
B4.13 Upgrading and rebuilding existing powerlines
B4.14 Construction and operation of electrochemical-battery or flywheel energy storage systems

B5. Categorical Exclusions Applicable to Conservation, Fossil, and Renewable Energy Activities

B5.1 Actions to conserve energy or water
B5.2 Modifications to pumps and piping
B5.3 Modification or abandonment of wells
B5.4 Repair or replacement of pipelines
B5.5 Short pipeline segments
B5.6 Oil spill cleanup
B5.7 Export of natural gas and associated transportation by marine vessel
B5.8 [Reserved]
B5.9 Temporary exemptions for electric powerplants
B5.10 Certain permanent exemptions for existing electric powerplants
B5.11 Permanent exemptions allowing mixed natural gas and petroleum
B5.12 Workover of existing wells
B5.13 Experimental wells for injection of small quantities of carbon dioxide
B5.14 Combined heat and power or cogeneration systems
B5.15 Small-scale renewable energy research and development and pilot projects
B5.16 Solar photovoltaic systems
B5.17 Solar thermal systems
B5.18 Wind turbines
B5.19 Ground source heat pumps
B5.20 Biomass power plants
B5.21 Methane gas recovery and utilization systems
B5.22 Alternative fuel vehicle fueling stations
B5.23 Electric vehicle charging stations
B5.24 Drop-in hydroelectric systems
B5.25 Small-scale renewable energy research and development and pilot projects in aquatic environments
B5.26 Advanced nuclear reactors

B6. Categorical Exclusions Applicable to Environmental Restoration and Waste Management Activities

B6.1 Cleanup actions
B6.2 Waste collection, treatment, stabilization, and containment facilities
B6.3 Improvements to environmental control systems

B6.4 Facilities for storing packaged hazardous waste for 90 days or less
B6.5 Facilities for characterizing and sorting packaged waste and overpacking waste
B6.6 Modification of facilities for storing, packaging, and repacking waste
B6.7 [Reserved]
B6.8 Modifications for waste minimization and reuse of materials
B6.9 Measures to reduce migration of contaminated groundwater
B6.10 Upgraded or replacement waste storage facilities

B7. Categorical Exclusions Applicable to International Activities

B7.1 Emergency measures under the International Energy Program
B7.2 Import and export of special nuclear or isotopic materials

B. Conditions That Are Integral Elements of the Classes of Actions in Appendix B

The classes of actions listed below include the following conditions as integral elements of the classes of actions. To fit within the classes of actions listed below, a proposal must be one that would not:

(1) Threaten a violation of applicable statutory, regulatory, or permit requirements for environment, safety, and health, or similar requirements of DOE or Executive Orders;

(2) Require siting and construction or major expansion of waste storage, disposal, recovery, or treatment facilities (including incinerators), but the proposal may include categorically excluded waste storage, disposal, recovery, or treatment actions or facilities;

(3) Disturb hazardous substances, pollutants, contaminants, or CERCLA-excluded petroleum and natural gas products that preexist in the environment such that there would be uncontrolled or unpermitted releases;

(4) Have the potential to cause significant impacts on environmentally sensitive resources. An environmentally sensitive resource is typically a resource that has been identified as needing protection through Executive Order, statute, or regulation by Federal, state, or local government, or a Federally recognized Indian tribe. An action may be categorically excluded if, although sensitive resources are present, the action would not have the potential to cause significant impacts on those resources (such as construction of a building with its foundation well above a sole-source aquifer or upland surface soil removal on a site that has wetlands). Environmentally sensitive resources include, but are not limited to:

(i) Property (such as sites, buildings, structures, and objects) of historic, archeological, or architectural significance designated by a Federal, state, or local government, Federally recognized Indian tribe, or Native Hawaiian organization, or property determined to be eligible for listing on the National Register of Historic Places;

(ii) Federally-listed threatened or endangered species or their habitat (including critical habitat) or Federally-proposed or candidate species or their habitat (Endangered Species Act); state-listed or state-proposed endangered or threatened species or their habitat; Federally-protected marine mammals and Essential Fish Habitat (Marine Mammal Protection Act; Magnuson-Stevens Fishery Conservation and Management Act); and otherwise Federally-protected species (such as the Bald and Golden Eagle Protection Act or the Migratory Bird Treaty Act);

(iii) Floodplains and wetlands (as defined in 10 CFR 1022.4, "Compliance with Floodplain and Wetland Environmental Review Requirements: Definitions," or its successor);

(iv) Areas having a special designation such as Federally- and state-designated wilderness areas, national parks, national monuments, national natural landmarks, wild and scenic rivers, state and Federal wildlife refuges, scenic areas (such as National Scenic and Historic Trails or National Scenic Areas), and marine sanctuaries;

(v) Prime or unique farmland, or other farmland of statewide or local importance, as defined at 7 CFR 658.2(a), "Farmland Protection Policy Act: Definitions," or its successor;

(vi) Special sources of water (such as sole-source aquifers, wellhead protection areas, and other water sources that are vital in a region); and

(vii) Tundra, coral reefs, or rain forests; or

(5) Involve genetically engineered organisms, synthetic biology, governmentally designated noxious weeds, or invasive species, unless the proposed activity would be contained or confined in a manner designed and operated to prevent unauthorized release into the environment and conducted in accordance with applicable requirements, such as those of the Department of Agriculture, the Environmental Protection Agency, and the National Institutes of Health.

B1. Categorical Exclusions Applicable to Facility Operation

B1.1 Changing rates and prices

Changing rates for services or prices for products marketed by parts of DOE other than Power Marketing Administrations, and approval of rate or price changes for non-DOE entities, that are consistent with the change in the implicit price deflator for the Gross Domestic Product published by the Department of Commerce, during the period since the last rate or price change.

B1.2 Training exercises and simulations

Training exercises and simulations (including, but not limited to, firing-range training, small-scale and short-duration force-on-force exercises, emergency response training, fire fighter and rescue training, and decontamination and spill cleanup training) conducted under appropriately controlled conditions and in accordance with applicable requirements.

B1.3 Routine maintenance

Routine maintenance activities and custodial services for buildings, structures, rights-of-way, infrastructures (including, but not limited to, pathways, roads, and railroads), vehicles and equipment, and localized vegetation and pest control, during which operations may be suspended and resumed, provided that the activities would be conducted in a manner in accordance with applicable requirements. Custodial services are activities to preserve facility appearance, working conditions, and sanitation (such as cleaning, window washing, lawn mowing, trash collection, painting, and snow removal). Routine maintenance activities, corrective (that is, repair), preventive, and predictive, are required to maintain and preserve buildings, structures, infrastructures, and equipment in a condition suitable for a facility to be used for its designated purpose. Such maintenance may occur as a result of severe weather (such as hurricanes, floods, and tornados), wildfires, and other such events. Routine maintenance may result in replacement to the extent that replacement is in-kind and is not a substantial upgrade or improvement. In-kind replacement includes installation of new components to replace outmoded components, provided that the replacement does not result in a significant change in the expected useful life, design capacity, or function of the facility. Routine maintenance does not include replacement of a major component that significantly extends the originally intended useful life of a facility (for example, it does not include the replacement of a reactor vessel near the end of its useful life). Routine maintenance activities include, but are not limited to:

(a) Repair or replacement of facility equipment, such as lathes, mills, pumps, and presses;

(b) Door and window repair or replacement;

(c) Wall, ceiling, or floor repair or replacement;

(d) Reroofing;

(e) Plumbing, electrical utility, lighting, and telephone service repair or replacement;

(f) Routine replacement of high-efficiency particulate air filters;

(g) Inspection and/or treatment of currently installed utility poles;

(h) Repair of road embankments;

(i) Repair or replacement of fire protection sprinkler systems;

(j) Road and parking area resurfacing, including construction of temporary access to facilitate resurfacing, and scraping and grading of unpaved surfaces;

(k) Erosion control and soil stabilization measures (such as reseeding, gabions, grading, and revegetation);

(l) Surveillance and maintenance of surplus facilities in accordance with DOE Order 435.1, "Radioactive Waste Management," or its successor;

(m) Repair and maintenance of transmission facilities, such as replacement of conductors of the same nominal voltage, poles, circuit breakers, transformers, capacitors, crossarms, insulators, and downed powerlines, in accordance, where appropriate, with 40 CFR part 761 (Polychlorinated Biphenyls Manufacturing, Processing, Distribution in Commerce, and Use Prohibitions) or its successor;

(n) Routine testing and calibration of facility components, subsystems, or portable equipment (such as control valves, in-core monitoring devices, transformers, capacitors, monitoring wells, lysimeters, weather stations, and flumes);

(o) Routine decontamination of the surfaces of equipment, rooms, hot cells, or other interior surfaces of buildings (by such activities as wiping with rags, using strippable latex, and minor vacuuming), and removal of contaminated intact equipment and other material (not including spent nuclear fuel or special nuclear material in nuclear reactors); and

(p) Removal of debris.

B1.4 Air conditioning systems for existing equipment

Installation or modification of air conditioning systems required for temperature control for operation of existing equipment.

B1.5 Existing steam plants and cooling water systems

Minor improvements to existing steam plants and cooling water systems (including, but not limited to, modifications of existing cooling towers and ponds), provided that the improvements would not: (1) Create new sources of water or involve new receiving waters; (2) have the potential to significantly alter water withdrawal rates; (3) exceed the permitted temperature of discharged water; or (4) increase introductions of, or involve new introductions of, hazardous substances, pollutants, contaminants, or CERCLA-excluded petroleum and natural gas products.

B1.6 Tanks and equipment to control runoff and spills

Installation or modification of retention tanks or small (normally under one acre) basins and associated piping and pumps for existing operations to control runoff or spills (such as under 40 CFR part 112). Modifications include, but are not limited to, installing liners or covers. (See also B1.33 of this appendix.)

B1.7 Electronic equipment

Acquisition, installation, operation, modification, and removal of electricity transmission control and monitoring devices for grid demand and response, communication systems, data processing equipment, and similar electronic equipment.

B1.8 Screened water intake and outflow structures

Modifications to screened water intake and outflow structures such that intake velocities and volumes and water effluent quality and volumes are consistent with existing permit limits.

B1.9 Airway safety markings and painting

Placement of airway safety markings on, painting of, and repair and in-kind replacement of lighting on powerlines and antenna structures, wind turbines, and similar structures in accordance with applicable requirements (such as Federal Aviation Administration standards).

B1.10 Onsite storage of activated material

Routine, onsite storage at an existing facility of activated equipment and material (including, but not limited to, lead) used at that facility, to allow reuse after decay of radioisotopes with short half-lives.

B1.11 Fencing

Installation of fencing, including, but not limited to border marking, that would not have the potential to significantly impede wildlife population movement (including migration) or surface water flow.

B1.12 Detonation or burning of explosives or propellants after testing

Outdoor detonation or burning of explosives or propellants that failed (duds), were damaged (such as by fracturing), or were otherwise not consumed in testing. Outdoor detonation or burning would be in areas designated and routinely used for those purposes under existing applicable permits issued by Federal, state, and local authorities (such as a permit for a RCRA miscellaneous unit (40 CFR part 264, subpart X)).

B1.13 Pathways, short access roads, and rail lines

Construction, acquisition, and relocation, consistent with applicable right-of-way conditions and approved land use or transportation improvement plans, of pedestrian walkways and trails, bicycle paths, small outdoor fitness areas, and short access roads and rail lines (such as branch and spur lines).

B1.14 Refueling of nuclear reactors

Refueling of operating nuclear reactors, during which operations may be suspended and then resumed.

B1.15 Support buildings

Siting, construction or modification, and operation of support buildings and support structures (including, but not limited to, trailers and prefabricated and modular buildings) within or contiguous to an already developed area (where active utilities and currently used roads are readily accessible). Covered support buildings and structures include, but are not limited to, those for office purposes; parking; cafeteria services; education and training; visitor reception; computer and data processing services; health services or recreation activities; routine maintenance activities; storage of supplies and equipment for administrative services and routine maintenance activities; security (such as security posts); fire protection; small-scale fabrication (such as machine shop activities), assembly, and testing of non- nuclear equipment or components; and similar support purposes, but exclude facilities for nuclear weapons activities and waste storage activities, such as activities covered in B1.10, B1.29, B1.35, B2.6, B6.2, B6.4, B6.5, B6.6, and B6.10 of this appendix.

B1.16 Asbestos removal

Removal of asbestos-containing materials from buildings in accordance with applicable requirements (such as 40 CFR part 61, “National Emission Standards for Hazardous Air Pollutants”; 40 CFR part 763, “Asbestos”; 29 CFR part 1910, subpart I, “Personal Protective Equipment”; and 29 CFR part 1926, “Safety and Health Regulations for Construction”; and appropriate state and local requirements, including certification of removal contractors and technicians).

B1.17 Polychlorinated biphenyl removal

Removal of polychlorinated biphenyl (PCB)-containing items (including, but not limited to, transformers and capacitors), PCB-containing oils flushed from transformers, PCB-flushing solutions, and PCB- containing spill materials from buildings or other aboveground locations in accordance with applicable requirements (such as 40 CFR part 761).

B1.18 Water supply wells

Siting, construction, and operation of additional water supply wells (or replacement wells) within an existing well field, or modification of an existing water supply well to restore production, provided that there would be no drawdown other than in the immediate vicinity of the pumping well, and the covered actions would not have the potential to cause significant long-term decline of the water table, and would not have the potential to cause significant degradation of the aquifer from the new or replacement well.

B1.19 Microwave, meteorological, and radio towers

Siting, construction, modification, operation, and removal of microwave, radio communication, and meteorological towers and associated facilities, provided that the towers and associated facilities would not be in a governmentally designated scenic area (see B(4)(iv) of this appendix) unless otherwise authorized by the appropriate governmental entity.

B1.20 Protection of cultural resources, fish and wildlife habitat

Small-scale activities undertaken to protect cultural resources (such as fencing, labeling, and flagging) or to protect, restore, or improve fish and wildlife habitat, fish passage facilities (such as fish ladders and minor diversion channels), or fisheries. Such activities would be conducted in accordance with an existing natural or cultural resource plan, if any.

B1.21 Noise abatement

Noise abatement measures (including, but not limited to, construction of noise barriers and installation of noise control materials).

B1.22 Relocation of buildings

Relocation of buildings (including, but not limited to, trailers and prefabricated buildings) to an already developed area (where active utilities and currently used roads are readily accessible).

B1.23 Demolition and disposal of buildings

Demolition and subsequent disposal of buildings, equipment, and support structures (including, but not limited to, smoke stacks and parking lot surfaces), provided that there would be no potential for release of substances at a level, or in a form, that could pose a threat to public health or the environment.

B1.24 Property transfers

Transfer, lease, disposition, or acquisition of interests in personal property (including, but not limited to, equipment and materials) or real property (including, but not limited to, permanent structures and land), provided that under reasonably foreseeable uses (1) there would be no potential for release of substances at a level, or in a form, that could pose a threat to public health or the environment and (2) the covered actions would not have the potential to cause a significant change in impacts from before the transfer, lease, disposition, or acquisition of interests.

B1.25 Real property transfers for cultural resources protection, habitat preservation, and wildlife management

Transfer, lease, disposition, or acquisition of interests in land and associated buildings for cultural resources protection, habitat preservation, or fish and wildlife management, provided that there would be no potential for release of substances at a level, or in a form, that could pose a threat to public health or the environment.

B1.26 Small water treatment facilities

Siting, construction, expansion, modification, replacement, operation, and decommissioning of small (total capacity less than approximately 250,000 gallons per day) wastewater and surface water treatment facilities whose liquid discharges are externally regulated, and small potable water and sewage treatment facilities.

B1.27 Disconnection of utilities

Activities that are required for the disconnection of utility services (including, but not limited to, water, steam, telecommunications, and electrical power) after it has been determined that the continued operation of these systems is not needed for safety.

B1.28 Placing a facility in an environmentally safe condition

Minor activities that are required to place a facility in an environmentally safe condition where there is no proposed use for the facility. These activities would include, but are not limited to, reducing surface contamination, and removing materials, equipment or waste (such as final defueling of a reactor, where there are adequate existing facilities for the treatment, storage, or disposal of the materials, equipment or waste). These activities would not include conditioning, treatment, or processing of spent nuclear fuel, high-level waste, or special nuclear materials.

B1.29 Disposal facilities for construction and demolition waste

Siting, construction, expansion, modification, operation, and decommissioning of small (less than approximately 10 acres) solid waste disposal facilities for construction and demolition waste, in accordance with applicable requirements (such as 40 CFR part 257,

"Criteria for Classification of Solid Waste Disposal Facilities and Practices," and 40 CFR part 61, "National Emission Standards for Hazardous Air Pollutants") that would not release substances at a level, or in a form, that could pose a threat to public health or the environment.

B1.30 Transfer actions

Transfer actions, in which the predominant activity is transportation, provided that (1) the receipt and storage capacity and management capability for the amount and type of materials, equipment, or waste to be moved already exists at the receiving site and (2) all necessary facilities and operations at the receiving site are already permitted, licensed, or approved, as appropriate. Such transfers are not regularly scheduled as part of ongoing routine operations.

B1.31 Installation or relocation of machinery and equipment

Installation or relocation and operation of machinery and equipment (including, but not limited to, laboratory equipment, electronic hardware, manufacturing machinery, maintenance equipment, and health and safety equipment), provided that uses of the installed or relocated items are consistent with the general missions of the receiving structure. Covered actions include modifications to an existing building, within or contiguous to a previously disturbed or developed area, that are necessary for equipment installation and relocation. Such modifications would not appreciably increase the footprint or height of the existing building or have the potential to cause significant changes to the type and magnitude of environmental impacts.

B1.32 Traffic flow adjustments

Traffic flow adjustments to existing roads (including, but not limited to, stop sign or traffic light installation, adjusting direction of traffic flow, and adding turning lanes), and road adjustments (including, but not limited to, widening and realignment) that are within an existing right-of-way and consistent with approved land use or transportation improvement plans.

B1.33 Stormwater runoff control

Design, construction, and operation of control practices to reduce stormwater runoff and maintain natural hydrology. Activities include, but are not limited to, those that reduce impervious surfaces (such as vegetative practices and use of porous pavements), best management practices (such as silt fences, straw wattles, and fiber rolls), and use of green infrastructure or other low impact development practices (such as cisterns and green roofs).

B1.34 Lead-based paint containment, removal, and disposal

Containment, removal, and disposal of lead-based paint in accordance with applicable requirements (such as provisions relating to the certification of removal contractors and technicians at 40 CFR part 745, "Lead-Based Paint Poisoning Prevention In Certain Residential Structures").

B1.35 Drop-off, collection, and transfer facilities for recyclable materials

Siting, construction, modification, and operation of recycling or compostable material drop-off, collection, and transfer stations on or contiguous to a previously disturbed or developed area and in an area where such a facility would be consistent with existing zoning requirements. The stations would have appropriate facilities and procedures established in accordance with applicable requirements for the handling of recyclable or compostable materials and household hazardous waste (such as paint and pesticides). Except as specified above, the collection of hazardous waste for disposal and the processing of recyclable or compostable materials are not included in this class of actions.

B1.36 Determinations of excess real property

Determinations that real property is excess to the needs of DOE and, in the case of acquired real property, the subsequent reporting of such determinations to the General Services Administration or, in the case of lands withdrawn or otherwise reserved from the public domain, the subsequent filing of a notice of intent to relinquish with the Bureau of Land Management, Department of the Interior. Covered actions would not include disposal of real property.

B2. Categorical Exclusions Applicable to Safety and Health

B2.1 Workplace enhancements

Modifications within or contiguous to an existing structure, in a previously disturbed or developed area, to enhance workplace habitability (including, but not limited to, installation or improvements to lighting, radiation shielding, or heating/ventilating/air conditioning and its instrumentation, and noise reduction).

B2.2 Building and equipment instrumentation

Installation of, or improvements to, building and equipment instrumentation (including, but not limited to, remote control panels, remote monitoring capability, alarm and surveillance systems, control systems to provide automatic shutdown, fire detection and protection systems, water consumption monitors and flow control systems, announcement and emergency warning systems, criticality and radiation monitors and alarms, and safeguards and security equipment).

B2.3 Personnel safety and health equipment

Installation of, or improvements to, equipment for personnel safety and health (including, but not limited to, eye washes, safety showers, radiation monitoring devices, fumehoods, and associated collection and exhaust systems), provided that the covered actions would not have the potential to cause a significant increase in emissions.

B2.4 Equipment qualification

Activities undertaken to (1) qualify equipment for use or improve systems reliability or (2) augment information on safety-related system components. These activities include, but are not limited to, transportation container qualification testing, crane and lift-gear certification or recertification testing, high efficiency particulate air filter testing and certification, stress tests (such as "burn-in" testing of electrical components and leak testing), and calibration of sensors or diagnostic equipment.

B2.5 Facility safety and environmental improvements

Safety and environmental improvements of a facility (including, but not limited to, replacement and upgrade of facility components) that do not result in a significant change in the expected useful life, design capacity, or function of the facility and during which operations may be suspended and then resumed. Improvements include, but are not limited to, replacement/upgrade of control valves, in-core monitoring devices, facility air filtration systems, or substation transformers or capacitors; addition of structural bracing to meet earthquake standards and/or sustain high wind loading; and replacement of aboveground or belowground tanks and related piping, provided that there is no evidence of leakage, based on testing in accordance with applicable requirements (such as 40 CFR part 265, "Interim Status Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities" and 40 CFR part 280, "Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks"). These actions do not include rebuilding or modifying substantial portions of a facility (such as replacing a reactor vessel).

B2.6 Recovery of radioactive sealed sources

Recovery of radioactive sealed sources and sealed source-containing devices from domestic or foreign locations provided that (1) the recovered items are transported and stored in compliant containers, and (2) the receiving site has sufficient existing storage capacity and all required licenses, permits, and approvals.

B3. Categorical Exclusions Applicable to Site Characterization, Monitoring, and General Research

B3.1 Site characterization and environmental monitoring

Site characterization and environmental monitoring (including, but not limited to, siting, construction, modification, operation, and dismantlement and removal or otherwise proper closure (such as of a well) of characterization and monitoring devices, and siting, construction, and associated operation of a small-scale laboratory building or renovation of a room in an existing building for sample analysis). Such activities would be designed in conformance with applicable requirements and use best management practices to limit the potential effects of any resultant ground disturbance. Covered activities include, but are not limited to, site characterization and environmental monitoring under CERCLA and RCRA. (This class of actions excludes activities in aquatic environments. See B3.16 of this appendix for such activities.) Specific activities include, but are not limited to:

(a) Geological, geophysical (such as gravity, magnetic, electrical, seismic, radar, and temperature gradient), geochemical, and engineering surveys and mapping, and the establishment of survey marks. Seismic techniques would not include large-scale reflection or refraction testing;

(b) Installation and operation of field instruments (such as stream-gauging stations or flow-measuring devices, telemetry systems, geochemical monitoring tools, and geophysical exploration tools);

(c) Drilling of wells for sampling or monitoring of groundwater or the vadose (unsaturated) zone, well logging, and installation of water-level recording devices in wells;

(d) Aquifer and underground reservoir response testing;

(e) Installation and operation of ambient air monitoring equipment;

(f) Sampling and characterization of water, soil, rock, or contaminants (such as drilling using truck- or mobile- scale equipment, and modification, use, and plugging of boreholes);

(g) Sampling and characterization of water effluents, air emissions, or solid waste streams;

(h) Installation and operation of meteorological towers and associated activities (such as assessment of potential wind energy resources);

(i) Sampling of flora or fauna; and

(j) Archeological, historic, and cultural resource identification in compliance with 36 CFR part 800 and 43 CFR part 7.

B3.2 Aviation activities

Aviation activities for survey, monitoring, or security purposes that comply with Federal

Aviation Administration regulations.

B3.3 Research related to conservation of fish, wildlife, and cultural resources

Field and laboratory research, inventory, and information collection activities that are directly related to the conservation of fish and wildlife resources or to the protection of cultural resources, provided that such activities would not have the potential to cause significant impacts on fish and wildlife habitat or populations or to cultural resources.

B3.4 Transport packaging tests for radioactive or hazardous material

Drop, puncture, water-immersion, thermal, and fire tests of transport packaging for radioactive or hazardous materials to certify that designs meet the applicable requirements (such as 49 CFR 173.411 and 173.412 and 10 CFR 71.73).

B3.5 Tank car tests

Tank car tests under 49 CFR part 179 (including, but not limited to, tests of safety relief devices, pressure regulators, and thermal protection systems).

B3.6 Small-scale research and development, laboratory operations, and pilot projects

Siting, construction, modification, operation, and decommissioning of facilities for small-scale research and development projects; conventional laboratory operations (such as preparation of chemical standards and sample analysis); and small-scale pilot projects (generally less than 2 years) frequently conducted to verify a concept before demonstration actions, provided that construction or modification would be within or contiguous to a previously disturbed or developed area (where active utilities and currently used roads are readily accessible). Not included in this category are demonstration actions, meaning actions that are undertaken at a scale to show whether a technology would be viable on a larger scale and suitable for commercial deployment.

B3.7 New terrestrial infill exploratory and experimental wells

Siting, construction, and operation of new terrestrial infill exploratory and experimental (test) wells, for either extraction or injection use, in a locally characterized geological formation in a field that contains existing operating wells, properly abandoned wells, or unminable coal seams containing natural gas, provided that the site characterization has verified a low potential for seismicity, subsidence, and contamination of freshwater aquifers, and the actions are otherwise consistent with applicable best practices and DOE protocols, including those that protect against uncontrolled releases of harmful materials. Such wells may include those for brine, carbon dioxide, coalbed methane, gas hydrate, geothermal, natural gas, and oil. Uses for carbon sequestration wells include, but are not limited to, the study of saline formations, enhanced oil recovery, and enhanced coalbed

methane extraction.

B3.8 Outdoor terrestrial ecological and environmental research

Outdoor terrestrial ecological and environmental research in a small area (generally less than 5 acres), including, but not limited to, siting, construction, and operation of a small-scale laboratory building or renovation of a room in an existing building for associated analysis. Such activities would be designed in conformance with applicable requirements and use best management practices to limit the potential effects of any resultant ground disturbance.

B3.9 Projects to reduce emissions and waste generation

Projects to reduce emissions and waste generation at existing fossil or alternative fuel combustion or utilization facilities, provided that these projects would not have the potential to cause a significant increase in the quantity or rate of air emissions. For this category of actions, "fuel" includes, but is not limited to, coal, oil, natural gas, hydrogen, syngas, and biomass; but "fuel" does not include nuclear fuel. Covered actions include, but are not limited to:

(a) Test treatment of the throughput product (solid, liquid, or gas) generated at an existing and fully operational fuel combustion or utilization facility;

(b) Addition or replacement of equipment for reduction or control of sulfur dioxide, oxides of nitrogen, or other regulated substances that requires only minor modification to the existing structures at an existing fuel combustion or utilization facility, for which the existing use remains essentially unchanged;

(c) Addition or replacement of equipment for reduction or control of sulfur dioxide, oxides of nitrogen, or other regulated substances that involves no permanent change in the quantity or quality of fuel burned or used and involves no permanent change in the capacity factor of the fuel combustion or utilization facility; and

(d) Addition or modification of equipment for capture and control of carbon dioxide or other regulated substances, provided that adequate infrastructure is in place to manage such substances.

B3.10 Particle accelerators

Siting, construction, modification, operation, and decommissioning of particle accelerators, including electron beam accelerators, with primary beam energy less than approximately 100 million electron volts (MeV) and average beam power less than approximately 250 kilowatts (kW), and associated beamlines, storage rings, colliders, and detectors, for research and medical purposes (such as proton therapy), and isotope

production, within or contiguous to a previously disturbed or developed area (where active utilities and currently used roads are readily accessible), or internal modification of any accelerator facility regardless of energy, that does not increase primary beam energy or current. In cases where the beam energy exceeds 100 MeV, the average beam power must be less than 250 kW, so as not to exceed an average current of 2.5 milliamperes (mA).

B3.11 Outdoor tests and experiments on materials and equipment components

Outdoor tests and experiments for the development, quality assurance, or reliability of materials and equipment (including, but not limited to, weapon system components) under controlled conditions. Covered actions include, but are not limited to, burn tests (such as tests of electric cable fire resistance or the combustion characteristics of fuels), impact tests (such as pneumatic ejector tests using earthen embankments or concrete slabs designated and routinely used for that purpose), or drop, puncture, water-immersion, or thermal tests. Covered actions would not involve source, special nuclear, or byproduct materials, except encapsulated sources manufactured to applicable standards that contain source, special nuclear, or byproduct materials may be used for nondestructive actions such as detector/sensor development and testing and first responder field training.

B3.12 Microbiological and biomedical facilities

Siting, construction, modification, operation, and decommissioning of microbiological and biomedical diagnostic, treatment and research facilities (excluding Biosafety Level-3 and Biosafety Level-4), in accordance with applicable requirements and best practices (such as Biosafety in Microbiological and Biomedical Laboratories, 5th Edition, Dec. 2009, U.S. Department of Health and Human Services) including, but not limited to, laboratories, treatment areas, offices, and storage areas, within or contiguous to a previously disturbed or developed area (where active utilities and currently used roads are readily accessible). Operation may include the purchase, installation, and operation of biomedical equipment (such as commercially available cyclotrons that are used to generate radioisotopes and radiopharmaceuticals, and commercially available biomedical imaging and spectroscopy instrumentation).

B3.13 Magnetic fusion experiments

Performing magnetic fusion experiments that do not use tritium as fuel, within existing facilities (including, but not limited to, necessary modifications).

B3.14 Small-scale educational facilities

Siting, construction, modification, operation, and decommissioning of small-scale educational facilities (including, but not limited to, conventional teaching laboratories, libraries, classroom facilities, auditoriums, museums, visitor centers, exhibits, and

associated offices) within or contiguous to a previously disturbed or developed area (where active utilities and currently used roads are readily accessible). Operation may include, but is not limited to, purchase, installation, and operation of equipment (such as audio/visual and laboratory equipment) commensurate with the educational purpose of the facility.

B3.15 Small-scale indoor research and development projects using nanoscale materials

Siting, construction, modification, operation, and decommissioning of facilities for indoor small-scale research and development projects and small-scale pilot projects using nanoscale materials in accordance with applicable requirements (such as engineering, worker safety, procedural, and administrative regulations) necessary to ensure the containment of any hazardous materials. Construction and modification activities would be within or contiguous to a previously disturbed or developed area (where active utilities and currently used roads are readily accessible).

B3.16 Research activities in aquatic environments

Small-scale, temporary surveying, site characterization, and research activities in aquatic environments, limited to:

(a) Acquisition of rights-of-way, easements, and temporary use permits;

(b) Installation, operation, and removal of passive scientific measurement devices, including, but not limited to, antennae, tide gauges, flow testing equipment for existing wells, weighted hydrophones, salinity measurement devices, and water quality measurement devices;

(c) Natural resource inventories, data and sample collection, environmental monitoring, and basic and applied research, excluding

(1) large-scale vibratory coring techniques and

(2) seismic activities other than passive techniques; and

(d) Surveying and mapping.

These activities would be conducted in accordance with, where applicable, an approved spill prevention, control, and response plan and would incorporate appropriate control technologies and best management practices. None of the activities listed above would occur within the boundary of an established marine sanctuary or wildlife refuge, a governmentally proposed marine sanctuary or wildlife refuge, or a governmentally recognized area of high biological sensitivity, unless authorized by the agency responsible

for such refuge, sanctuary, or area (or after consultation with the responsible agency, if no authorization is required). If the proposed activities would occur outside such refuge, sanctuary, or area and if the activities would have the potential to cause impacts within such refuge, sanctuary, or area, then the responsible agency shall be consulted in order to determine whether authorization is required and whether such activities would have the potential to cause significant impacts on such refuge, sanctuary, or area. Areas of high biological sensitivity include, but are not limited to, areas of known ecological importance, whale and marine mammal mating and calving/pupping areas, and fish and invertebrate spawning and nursery areas recognized as being limited or unique and vulnerable to perturbation; these areas can occur in bays, estuaries, near shore, and far offshore, and may vary seasonally. No permanent facilities or devices would be constructed or installed. Covered actions do not include drilling of resource exploration or extraction wells.

B4. Categorical Exclusions Applicable to Electrical Power and Transmission

B4.1 Contracts, policies, and marketing and allocation plans for electric power

Establishment and implementation of contracts, policies, and marketing and allocation plans related to electric power acquisition that involve only the use of the existing transmission system and existing generation resources operating within their normal operating limits.

B4.2 Export of electric energy

Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission systems or using transmission system changes that are themselves categorically excluded.

B4.3 Electric power marketing rate changes

Rate changes for electric power, power transmission, and other products or services provided by a Power Marketing Administration that are based on a change in revenue requirements if the operations of generation projects would remain within normal operating limits.

B4.4 Power marketing services and activities

Power marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits. (*See* B4.14 of this appendix for energy storage systems.)

B4.5 Temporary adjustments to river operations

Temporary adjustments to river operations to accommodate day-to-day river fluctuations, power demand changes, fish and wildlife conservation program requirements, and other external events, provided that the adjustments would occur within the existing operating constraints of the particular hydrosystem operation.

B4.6 Additions and modifications to transmission facilities

Additions or modifications to electric power transmission facilities within a previously disturbed or developed facility area. Covered activities include, but are not limited to, switchyard rock grounding upgrades, secondary containment projects, paving projects, seismic upgrading, tower modifications, load shaping projects (such as reducing energy use during periods of peak demand), changing insulators, and replacement of poles, circuit breakers, conductors, transformers, and crossarms. (See B4.14 of this appendix for energy storage systems.)

B4.7 Fiber optic cable

Adding fiber optic cables to transmission facilities or burying fiber optic cable in existing powerline or pipeline rights-of-way. Covered actions may include associated vaults and pulling and tensioning sites outside of rights-of- way in nearby previously disturbed or developed areas.

B4.8 Electricity transmission agreements

New electricity transmission agreements, and modifications to existing transmission arrangements, to use a transmission facility of one system to transfer power of and for another system, provided that no new generation projects would be involved and no physical changes in the transmission system would be made beyond the previously disturbed or developed facility area.

B4.9 Multiple use of powerline rights-of-way

Granting or denying requests for multiple uses of a transmission facility's rights-of-way (including, but not limited to, grazing permits and crossing agreements for electric lines, water lines, natural gas pipelines, communications cables, roads, and drainage culverts).

B4.10 Removal of electric transmission facilities

Deactivation, dismantling, and removal of electric transmission facilities (including, but not limited to, electric powerlines, substations, and switching stations) and abandonment and restoration of rights-of-way (including, but not limited to, associated access roads).

B4.11 Electric power substations and interconnection facilities

Construction or modification of electric power substations or interconnection facilities (including, but not limited to, switching stations and support facilities).

B4.12 Construction of powerlines

Construction of electric powerlines approximately 10 miles in length or less, or approximately 20 miles in length or less within previously disturbed or developed powerline or pipeline rights-of-way.

B4.13 Upgrading and rebuilding existing powerlines

Upgrading or rebuilding existing electric powerlines, which may involve relocations of small segments of the powerlines within an existing powerline right-of-way or within otherwise previously disturbed or developed lands (as discussed at section 5.4(b)(1)). Upgrading or rebuilding existing electric powerlines also may involve widening an existing powerline right-of-way to meet current electrical standards if the widening remains within previously disturbed or developed lands and only extends into a small area beyond such lands as needed to comply with applicable electrical standards. Covered actions would be in accordance with applicable requirements, including the integral elements listed at the start of this appendix; and would incorporate appropriate design and construction standards, control technologies, and best management practices. This categorical exclusion does not apply to underwater powerlines. As used in this categorical exclusion, "small" has the meaning discussed at section 5.4(b)(2)).

B4.14 Construction and operation of electrochemical-battery or flywheel energy storage systems

Construction, operation, upgrade, or decommissioning of an electrochemical-battery or flywheel energy storage system within a previously disturbed or developed area or within a small (as discussed at section 5.4(b)(2)) area contiguous to a previously disturbed or developed area. Covered actions would be in accordance with applicable requirements (such as land use and zoning requirements) in the proposed project area and the integral elements listed at the start of this appendix, and would incorporate appropriate safety standards (including the current National Fire Protection Association 855, Standard for the Installation of Stationary Energy Storage Systems), design and construction standards, control technologies, and best management practices.

B5. Categorical Exclusions Applicable to Conservation, Fossil, and Renewable Energy Activities

B5.1 Actions to conserve energy or water

(a) Actions to conserve energy or water, demonstrate potential energy or water conservation, and promote energy efficiency that would not have the potential to cause

significant changes in the indoor or outdoor concentrations of potentially harmful substances. These actions may involve financial and technical assistance to individuals (such as builders, owners, consultants, manufacturers, and designers), organizations (such as utilities), and governments (such as state, local, and tribal). Covered actions include, but are not limited to weatherization (such as insulation and replacing windows and doors); programmed lowering of thermostat settings; placement of timers on hot water heaters; installation or replacement of energy efficient lighting, low-flow plumbing fixtures (such as faucets, toilets, and showerheads), heating, ventilation, and air conditioning systems, and appliances; installation of drip- irrigation systems; improvements in generator efficiency and appliance efficiency ratings; efficiency improvements for vehicles and transportation (such as fleet changeout); transportation management systems (such as traffic signal control systems, car navigation, speed cameras, and automatic plate number recognition); development of energy-efficient manufacturing, industrial, or building practices; and small-scale energy efficiency and conservation research and development and small-scale pilot projects. Covered actions include building renovations or new structures, provided that they occur in a previously disturbed or developed area. Covered actions could involve commercial, residential, agricultural, academic, institutional, or industrial sectors. Covered actions do not include rulemakings, standard- settings, or proposed DOE legislation, except for those actions listed in B5.1(b) of this appendix.

(b) Covered actions include rulemakings that establish energy conservation standards for consumer products and industrial equipment, provided that the actions would not:

(1) Have the potential to cause a significant change in manufacturing infrastructure (such as construction of new manufacturing plants with considerable associated ground disturbance);

(2) involve significant unresolved conflicts concerning alternative uses of available resources (such as rare or limited raw materials);

(3) have the potential to result in a significant increase in the disposal of materials posing significant risks to human health and the environment (such as RCRA hazardous wastes); or

(4) have the potential to cause a significant increase in energy consumption in a state or region.

B5.2 Modifications to pumps and piping

Modifications to existing pump and piping configurations (including, but not limited to, manifolds, metering systems, and other instrumentation on such configurations conveying materials such as air, brine, carbon dioxide, geothermal system fluids, hydrogen gas, natural gas, nitrogen gas, oil, produced water, steam, and water). Covered modifications

would not have the potential to cause significant changes to design process flow rates or permitted air emissions.

B5.3 Modification or abandonment of wells

Modification (but not expansion) or plugging and abandonment of wells, provided that site characterization has verified a low potential for seismicity, subsidence, and contamination of freshwater aquifers, and the actions are otherwise consistent with best practices and DOE protocols, including those that protect against uncontrolled releases of harmful materials. Such wells may include, but are not limited to, storage and injection wells for brine, carbon dioxide, coalbed methane, gas hydrate, geothermal, natural gas, and oil. Covered modifications would not be part of site closure.

B5.4 Repair or replacement of pipelines

Repair, replacement, upgrading, rebuilding, or minor relocation of pipelines within existing rights-of- way, provided that the actions are in accordance with applicable requirements (such as Army Corps of Engineers permits under section 404 of the Clean Water Act). Pipelines may convey materials including, but not limited to, air, brine, carbon dioxide, geothermal system fluids, hydrogen gas, natural gas, nitrogen gas, oil, produced water, steam, and water.

B5.5 Short pipeline segments

Construction and subsequent operation of short (generally less than 20 miles in length) pipeline segments conveying materials (such as air, brine, carbon dioxide, geothermal system fluids, hydrogen gas, natural gas, nitrogen gas, oil, produced water, steam, and water) between existing source facilities and existing receiving facilities (such as facilities for use, reuse, transportation, storage, and refining), provided that the pipeline segments are within previously disturbed or developed rights-of-way.

B5.6 Oil spill cleanup

Removal of oil and contaminated materials recovered in oil spill cleanup operations and disposal of these materials in accordance with applicable requirements (such as the National Oil and Hazardous Substances Pollution Contingency Plan).

B5.7 Export of natural gas and associated transportation by marine vessel

Approvals or disapprovals of new authorizations or amendments of existing authorizations to export natural gas under section 3 of the Natural Gas Act and any associated transportation of natural gas by marine vessel.

B5.8 [Reserved]

B5.9 Temporary exemptions for electric powerplants

Grants or denials of temporary exemptions under the Powerplant and Industrial Fuel Use Act of 1978, as amended, for electric powerplants.

B5.10 Certain permanent exemptions for existing electric powerplants

For existing electric powerplants, grants or denials of permanent exemptions under the Powerplant and Industrial Fuel Use Act of 1978, as amended, other than exemptions under section 312(c) relating to cogeneration and section 312(b) relating to certain state or local requirements.

B5.11 Permanent exemptions allowing mixed natural gas and petroleum

For new electric powerplants, grants or denials of permanent exemptions from the prohibitions of Title II of the Powerplant and Industrial Fuel Use Act of 1978, as amended, to permit the use of certain fuel mixtures containing natural gas or petroleum.

B5.12 Workover of existing wells

Workover (operations to restore production, such as deepening, plugging back, pulling and resetting lines, and squeeze cementing) of existing wells (including, but not limited to, activities associated with brine, carbon dioxide, coalbed methane, gas hydrate, geothermal, natural gas, and oil) to restore functionality, provided that workover operations are restricted to the existing wellpad and do not involve any new site preparation or earthwork that would have the potential to cause significant impacts on nearby habitat; that site characterization has verified a low potential for seismicity, subsidence, and contamination of freshwater aquifers; and the actions are otherwise consistent with best practices and DOE protocols, including those that protect against uncontrolled releases of harmful materials.

B5.13 Experimental wells for injection of small quantities of carbon dioxide

Siting, construction, operation, plugging, and abandonment of experimental wells for the injection of small quantities of carbon dioxide (and other incidentally co-captured gases) in locally characterized, geologically secure storage formations at or near existing carbon dioxide sources to determine the suitability of the formations for large-scale sequestration, provided that (1) The characterization has verified a low potential for seismicity, subsidence, and contamination of freshwater aquifers; (2) the wells are otherwise in accordance with applicable requirements, best practices, and DOE protocols, including those that protect against uncontrolled releases of harmful materials; and (3) the wells and associated drilling activities are sufficiently remote so that they would not have the potential to cause significant impacts related to noise and other vibrations. Wells may be used for enhanced oil or natural gas recovery or for secure

storage of carbon dioxide in saline formations or other secure formations. Over the duration of a project, the wells would be used to inject, in aggregate, less than 500,000 tons of carbon dioxide into the geologic formation. Covered actions exclude activities in aquatic environments. (See B3.16 of this appendix for activities in aquatic environments.)

B5.14 Combined heat and power or cogeneration systems

Conversion to, replacement of, or modification of combined heat and power or cogeneration systems (the sequential or simultaneous production of multiple forms of energy, such as thermal and electrical energy, in a single integrated system) at existing facilities, provided that the conversion, replacement, or modification would not have the potential to cause a significant increase in the quantity or rate of air emissions and would not have the potential to cause significant impacts to water resources.

B5.15 Small-scale renewable energy research and development and pilot projects

Small-scale renewable energy research and development projects and small-scale pilot projects, provided that the projects are located within a previously disturbed or developed area. Covered actions would be in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.16 Solar photovoltaic systems

(a) The installation, modification, operation, or decommissioning of commercially available solar photovoltaic systems:

(1) Located on a building or other structure (such as rooftop, parking lot or facility, or mounted to signage, lighting, gates, or fences); or

(2) Located within a previously disturbed or developed area.

(b) Covered actions would be in accordance with applicable requirements (such as land use and zoning requirements) in the proposed project area and the integral elements listed at the start of this appendix, and would be consistent with applicable plans for the management of wildlife and habitat, including plans to maintain habitat connectivity, and incorporate appropriate control technologies and best management practices.

B5.17 Solar thermal systems

The installation, modification, operation, and removal of commercially available small-scale solar thermal systems (including, but not limited to, solar hot water systems) located on or contiguous to a building, and if located on land, generally comprising less than 10 acres within a previously disturbed or developed area. Covered actions would be in

accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.18 Wind turbines

The installation, modification, operation, and removal of a small number (generally not more than 2) of commercially available wind turbines, with a total height generally less than 200 feet (measured from the ground to the maximum height of blade rotation) that (1) Are located within a previously disturbed or developed area; (2) are located more than 10 nautical miles (about 11.5 miles) from an airport or aviation navigation aid; (3) are located more than 1.5 nautical miles (about 1.7 miles) from National Weather Service or Federal Aviation Administration Doppler weather radar; (4) would not have the potential to cause significant impacts on bird or bat populations; and (5) are sited or designed such that the project would not have the potential to cause significant impacts to persons (such as from shadow flicker and other visual effects, and noise). Covered actions would be in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices. Covered actions include only those related to wind turbines to be installed on land.

B5.19 Ground source heat pumps

The installation, modification, operation, and removal of commercially available small-scale ground source heat pumps to support operations in single facilities (such as a school or community center) or contiguous facilities (such as an office complex) (1) Only where (a) major associated activities (such as drilling and discharge) are regulated, and (b) appropriate leakage and contaminant control measures would be in place (including for cross- contamination between aquifers); (2) that would not have the potential to cause significant changes in subsurface temperature; and (3) would be located within a previously disturbed or developed area. Covered actions would be in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.20 Biomass power plants

The installation, modification, operation, and removal of small-scale biomass power plants (generally less than 10 megawatts), using commercially available technology (1) Intended primarily to support operations in single facilities (such as a school and community center) or contiguous facilities (such as an office complex); (2) that would not affect the air quality attainment status of the area and would not have the potential to cause a significant increase in the quantity or rate of air emissions and would not have the potential to cause significant impacts to water resources; and (3) would be located within

a previously disturbed or developed area. Covered actions would be in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.21 Methane gas recovery and utilization systems

The installation, modification, operation, and removal of commercially available methane gas recovery and utilization systems installed within a previously disturbed or developed area on or contiguous to an existing landfill or wastewater treatment plant that would not have the potential to cause a significant increase in the quantity or rate of air emissions. Covered actions would be in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.22 Alternative fuel vehicle fueling stations

The installation, modification, operation, and removal of alternative fuel vehicle fueling stations (such as for compressed natural gas, hydrogen, ethanol and other commercially available biofuels) on the site of a current or former fueling station, or within a previously disturbed or developed area within the boundaries of a facility managed by the owners of a vehicle fleet. Covered actions would be in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.23 Electric vehicle charging stations

The installation, modification, operation, and removal of electric vehicle charging stations, using commercially available technology, within a previously disturbed or developed area. Covered actions are limited to areas where access and parking are in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.24 Drop-in hydroelectric systems

The installation, modification, operation, and removal of commercially available small-scale, drop-in, run-of-the-river hydroelectric systems that would (1) Involve no water storage or water diversion from the stream or river channel where the system is installed and (2) not have the potential to cause significant impacts on water quality, temperature, flow, or volume. Covered systems would be located up-gradient of an existing anadromous fish barrier that is not planned for removal and where fish passage retrofit is not planned and where there would not be the potential for significant impacts to threatened or endangered species or other species of concern (as identified in B(4)(ii) of this appendix).

Covered actions would involve no major construction or modification of stream or river channels, and the hydroelectric systems would be placed and secured in the channel without the use of heavy equipment. Covered actions would be in accordance with applicable requirements (such as local land use and zoning requirements) in the proposed project area and would incorporate appropriate control technologies and best management practices.

B5.25 Small-scale renewable energy research and development and pilot projects in aquatic environments

Small-scale renewable energy research and development projects and small-scale pilot projects located in aquatic environments. Activities would be in accordance with, where applicable, an approved spill prevention, control, and response plan, and would incorporate appropriate control technologies and best management practices. Covered actions would not occur (1) Within areas of hazardous natural bottom conditions or (2) within the boundary of an established marine sanctuary or wildlife refuge, a governmentally proposed marine sanctuary or wildlife refuge, or a governmentally recognized area of high biological sensitivity, unless authorized by the agency responsible for such refuge, sanctuary, or area (or after consultation with the responsible agency, if no authorization is required). If the proposed activities would occur outside such refuge, sanctuary, or area and if the activities would have the potential to cause impacts within such refuge, sanctuary, or area, then the responsible agency shall be consulted in order to determine whether authorization is required and whether such activities would have the potential to cause significant impacts on such refuge, sanctuary, or area. Areas of high biological sensitivity include, but are not limited to, areas of known ecological importance, whale and marine mammal mating and calving/pupping areas, and fish and invertebrate spawning and nursery areas recognized as being limited or unique and vulnerable to perturbation; these areas can occur in bays, estuaries, near shore, and far offshore, and may vary seasonally. No permanent facilities or devices would be constructed or installed. Covered actions do not include drilling of resource exploration or extraction wells, use of large-scale vibratory coring techniques, or seismic activities other than passive techniques.

B5.26 Advanced nuclear reactors

Authorization, siting, construction, operation, reauthorization, and decommissioning of advanced nuclear reactors, provided DOE determines that:

(1) the project's attributes, including potential fission product inventory, fuel type, reactor design, and operational plans, reduce sufficiently the risk of adverse offsite consequences from the release of radioactive or hazardous materials, and

(2) the project demonstrates that any hazardous waste, radioactive waste, or spent nuclear fuel generated by the project can be managed in accordance with applicable

requirements.

For the purposes of this category, a project may include multiple reactors within a nuclear facility.

B6. Categorical Exclusions Applicable to Environmental Restoration and Waste Management Activities

B6.1 Cleanup actions

Small-scale, short-term cleanup actions, under RCRA, Atomic Energy Act, or other authorities, less than approximately 10 million dollars in cost (in 2011 dollars), to reduce risk to human health or the environment from the release or threat of release of a hazardous substance other than high-level radioactive waste and spent nuclear fuel, including treatment (such as incineration, encapsulation, physical or chemical separation, and compaction), recovery, storage, or disposal of wastes at existing facilities currently handling the type of waste involved in the action. These actions include, but are not limited to:

(a) Excavation or consolidation of contaminated soils or materials from drainage channels, retention basins, ponds, and spill areas that are not receiving contaminated surface water or wastewater, if surface water or groundwater would not collect and if such actions would reduce the spread of, or direct contact with, the contamination;

(b) Removal of bulk containers (such as drums and barrels) that contain or may contain hazardous substances, pollutants, contaminants, CERCLA-excluded petroleum or natural gas products, or hazardous wastes (designated in 40 CFR part 261 or applicable state requirements), if such actions would reduce the likelihood of spillage, leakage, fire, explosion, or exposure to humans, animals, or the food chain;

(c) Removal of an underground storage tank including its associated piping and underlying containment systems in accordance with applicable requirements (such as RCRA, subtitle I; 40 CFR part 265, subpart J; and 40 CFR part 280, subparts F and G) if such action would reduce the likelihood of spillage, leakage, or the spread of, or direct contact with, contamination;

(d) Repair or replacement of leaking containers;

(e) Capping or other containment of contaminated soils or sludges if the capping or containment would not unduly limit future groundwater remediation and if needed to reduce migration of hazardous substances, pollutants, contaminants, or CERCLA-excluded petroleum and natural gas products into soil, groundwater, surface water, or air;

(f) Drainage or closing of man-made surface impoundments if needed to maintain the integrity of the structures;

(g) Confinement or perimeter protection using dikes, trenches, ditches, or diversions, or installing underground barriers, if needed to reduce the spread of, or direct contact with, the contamination;

(h) Stabilization, but not expansion, of berms, dikes, impoundments, or caps if needed to maintain integrity of the structures;

(i) Drainage controls (such as run-off or run-on diversion) if needed to reduce offsite migration of hazardous substances, pollutants, contaminants, or CERCLA-excluded petroleum or natural gas products or to prevent precipitation or run-off from other sources from entering the release area from other areas;

(j) Segregation of wastes that may react with one another or form a mixture that could result in adverse environmental impacts;

(k) Use of chemicals and other materials to neutralize the pH of wastes;

(l) Use of chemicals and other materials to retard the spread of the release or to mitigate its effects if the use of such chemicals would reduce the spread of, or direct contact with, the contamination;

(m) Installation and operation of gas ventilation systems in soil to remove methane or petroleum vapors without any toxic or radioactive co-contaminants if appropriate filtration or gas treatment is in place;

(n) Installation of fences, warning signs, or other security or site control precautions if humans or animals have access to the release; and

(o) Provision of an alternative water supply that would not create new water sources if necessary immediately to reduce exposure to contaminated household or industrial use water and continuing until such time as local authorities can satisfy the need for a permanent remedy.

B6.2 Waste collection, treatment, stabilization, and containment facilities

The siting, construction, and operation of temporary (generally less than 2 years) pilot-scale waste collection and treatment facilities, and pilot-scale (generally less than 1 acre) waste stabilization and containment facilities (including siting, construction, and operation of a small-scale laboratory building or renovation of a room in an existing building for sample analysis), provided that the action (1) Supports remedial investigations/feasibility studies under CERCLA, or similar studies under RCRA (such as

RCRA facility investigations/corrective measure studies) or other authorities and (2) would not unduly limit the choice of reasonable remedial alternatives (such as by permanently altering substantial site area or by committing large amounts of funds relative to the scope of the remedial alternatives).

B6.3 Improvements to environmental control systems

Improvements to environmental monitoring and control systems of an existing building or structure (such as changes to scrubbers in air quality control systems or ion-exchange devices and other filtration processes in water treatment systems), provided that during subsequent operations (1) Any substance collected by the environmental control systems would be recycled, released, or disposed of within existing permitted facilities and (2) there are applicable statutory or regulatory requirements or permit conditions for disposal, release, or recycling of any hazardous substance or CERCLA-excluded petroleum or natural gas products that are collected or released in increased quantity or that were not previously collected or released.

B6.4 Facilities for storing packaged hazardous waste for 90 days or less

Siting, construction, modification, expansion, operation, and decommissioning of an onsite facility for storing packaged hazardous waste (as designated in 40 CFR part 261) for 90 days or less or for longer periods as provided in 40 CFR 262.34(d), (e), or (f) (such as accumulation or satellite areas).

B6.5 Facilities for characterizing and sorting packaged waste and overpacking waste

Siting, construction, modification, expansion, operation, and decommissioning of an onsite facility for characterizing and sorting previously packaged waste or for overpacking waste, other than high-level radioactive waste, provided that operations do not involve unpacking waste. These actions do not include waste storage (covered under B6.4, B6.6, B6.10 of this appendix) or the handling of spent nuclear fuel.

B6.6 Modification of facilities for storing, packaging, and repacking waste

Modification (excluding increases in capacity) of an existing structure used for storing, packaging, or repacking waste other than high-level radioactive waste or spent nuclear fuel, to handle the same class of waste as currently handled at that structure.

B6.7 [Reserved]

B6.8 Modifications for waste minimization and reuse of materials

Minor operational changes at an existing facility to minimize waste generation and for reuse of materials. These changes include, but are not limited to, adding filtration and

recycle piping to allow reuse of machining oil, setting up a sorting area to improve process efficiency, and segregating two waste streams previously mingled and assigning new identification codes to the two resulting wastes.

B6.9 Measures to reduce migration of contaminated groundwater

Small-scale temporary measures to reduce migration of contaminated groundwater, including the siting, construction, operation, and decommissioning of necessary facilities. These measures include, but are not limited to, pumping, treating, storing, and reinjecting water, by mobile units or facilities that are built and then removed at the end of the action.

B6.10 Upgraded or replacement waste storage facilities

Siting, construction, modification, expansion, operation, and decommissioning of a small upgraded or replacement facility (less than approximately 50,000 square feet in area) within or contiguous to a previously disturbed or developed area (where active utilities and currently used roads are readily accessible) for storage of waste that is already at the site at the time the storage capacity is to be provided. These actions do not include the storage of high-level radioactive waste, spent nuclear fuel or any waste that requires special precautions to prevent nuclear criticality. (See also B6.4, B6.5, B6.6 of this appendix.)

B7. Categorical Exclusions Applicable to International Activities

B7.1 Emergency measures under the International Energy Program

Planning and implementation of emergency measures pursuant to the International Energy Program.

B7.2 Import and export of special nuclear or isotopic materials

Approval of import or export of small quantities of special nuclear materials or isotopic materials in accordance with applicable requirements (such as the Nuclear Non-Proliferation Act of 1978 and the “Procedures Established Pursuant to the Nuclear Non-Proliferation Act of 1978” (43 FR 25326, June 9, 1978)).

Appendix C: Categorical Exclusions Adopted Pursuant to NEPA Section 109

DOE has adopted the categorical exclusions listed below from other Federal agencies pursuant to section 109 of NEPA (42 U.S.C. 4336(c)). These categorical exclusions are available for use by all DOE offices pursuant to procedures contained in section 5.2. DOE's notices of adoption, cited below, may contain additional information relevant to the adoption and use of particular categorical exclusions. DOE maintains a webpage for adoptions of categorical exclusions pursuant to section 109 of NEPA, as amended (https://www.energy.gov/nepa/section-109-adopting-categorical-exclusions).

Strikeouts indicate an administrative change to the categorical exclusion text, as adopted, in alignment with Council on Environmental Quality (CEQ) guidance on categorical exclusions. CEQ's April 2026 guidance on "Establishing, Revising, Adopting, and Applying Categorical Exclusions Under the National Environmental Policy Act" provides for non-substantive changes when adopting another agency's categorical exclusion. Specifically, CEQ guidance states: "[i]f an agency needs to clarify that an adopted categorical exclusion applies to its proposed action despite non-substantive language in the categorical exclusion referencing the establishing agency, it may explain this in the public notice adopting the categorical exclusion."

U.S. Department of Agriculture Categorical Exclusions

USDA-24-1d-RD

Small-scale site-specific development. The following CEs apply to proposals where site development activities (including construction, expansion, repair, rehabilitation, or other improvements) for rural development purposes would impact not more than 10 acres of real property and would not cause a substantial increase in traffic. These CEs are identified in paragraphs (d)(24)(i)(A) through (J). This paragraph does not apply to new industrial proposals (such as ethanol and biodiesel production facilities).

. . . .

(D) Infrastructure to support utility systems such as water or wastewater facilities; headquarters, maintenance, equipment storage, or microwave facilities; and energy management systems.

(7 CFR 1b.4(d)(24)(i)(D))

DOE announced adoption of this categorical exclusion on June 16, 2026 (https://www.energy.gov/nepa/articles/doe-adoption-department-agriculture-cxs-june-16-2026).

USDA-24-3d-RD: Financial assistance for small-scale energy proposals.

. . . .

(B) Construction of electric power lines and associated facilities designed for or capable of operation at a nominal voltage of either:

(1) Less than 69 kilovolts (kV);

(2) Less than 230 kV if no more than 25 miles of line are involved; or

(3) 230 kV or greater involving no more than three miles of line, but not for the integration of major new generation resources into a bulk transmission system;

(7 CFR 1b.4(d)(24)(iii)(B))

DOE announced adoption of this categorical exclusion on June 16, 2026 (https://www.energy.gov/nepa/articles/doe-adoption-department-agriculture-cxs-june-16-2026).

USDA-34d-USFS

Post-fire rehabilitation activities, not to exceed 4,200 acres (such as tree planting, fence replacement, habitat restoration, heritage site restoration, repair of roads and trails, and repair of damage to minor facilities such as campgrounds), to repair or improve lands unlikely to recover to a management approved condition from wildland fire damage, or to repair or replace minor facilities damaged by fire. Such activities:

(i) Shall be conducted consistent with Agency and Departmental procedures and applicable land and resource management plans;

(ii) Shall not include the use of herbicides or pesticides or the construction of new permanent roads or other new permanent infrastructure; and

(iii) Shall be completed within 3 years following a wildland fire.

(7 CFR 1b.4(d)(34))

DOE announced adoption of this categorical exclusion (formerly U.S. Forest Service categorical exclusion (e)(11)) on July 23, 2024 (89 FR 59726).

USDA-35d-USFS

Harvest of live trees not to exceed 70 acres, requiring no more than 1/2 mile of temporary road construction. Do not use this category for even-aged regeneration harvest or vegetation type conversion. The proposed action may include incidental removal of trees for landings, skid trails, and road clearing. Examples include, but are not limited to:

(i) Removal of individual trees for sawlogs, specialty products, or fuelwood, and

(ii) Commercial thinning of overstocked stands to achieve the desired stocking level to increase health and vigor.

(7 CFR 1b.4(d)(35))

DOE announced adoption of this categorical exclusion on July 23, 2024 (formerly U.S. Forest Service categorical exclusion (e)(12)) (89 FR 59726).

USDA-36d-USFS

Salvage of dead and/or dying trees not to exceed 250 acres, requiring no more than 1⁄2 mile of temporary road construction. The proposed action may include incidental removal of live or dead trees for landings, skid trails, and road clearing. Examples include, but are not limited to:

(i) Harvest of a portion of a stand damaged by a wind or ice event and construction of a short temporary road to access the damaged trees, and

(ii) Harvest of fire-damaged trees.

(7 CFR 1b.4(d)(36))

DOE announced adoption of this categorical exclusion (formerly U.S. Forest Service categorical exclusion (e)(13)) on July 23, 2024 (89 FR 59726).

USDA-37d-USFS

Commercial and noncommercial sanitation harvest of trees to control insects or disease not to exceed 250 acres, requiring no more than 1/2 mile of temporary road construction, including removal of infested/infected trees and adjacent live uninfested/uninfected trees as determined necessary to control the spread of insects or disease. The proposed action may include incidental removal of live or dead trees for landings, skid trails, and road clearing. Examples include, but are not limited to:

(i) Felling and harvest of trees infested with southern pine beetles and immediately adjacent uninfested trees to control expanding spot infestations, and

(ii) Removal and/or destruction of infested trees affected by a new exotic insect or disease, such as emerald ash borer, Asian long horned beetle, and sudden oak death pathogen.

(7 CFR 1b.4(d)(37))

DOE announced adoption of this categorical exclusion (formerly U.S. Forest Service categorical exclusion (e)(14)) on July 23, 2024 (89 FR 59726).

USDA-40d-USFS

Restoring wetlands, streams, riparian areas or other water bodies by removing, replacing, or modifying water control structures such as, but not limited to, dams, levees, dikes, ditches, culverts, pipes, drainage tiles, valves, gates, and fencing, to allow waters to flow into natural channels and floodplains and restore natural flow regimes to the extent practicable where valid existing rights or special use authorizations are not unilaterally altered or canceled. Examples include but are not limited to:

(i) Repairing an existing water control structure that is no longer functioning properly with minimal dredging, excavation, or placement of fill, and does not involve releasing hazardous substances;

(ii) Installing a newly-designed structure that replaces an existing culvert to improve aquatic organism passage and prevent resource and property damage where the road or trail maintenance level does not change;

(iii) Removing a culvert and installing a bridge to improve aquatic and/or terrestrial organism passage or prevent resource or property damage where the road or trail maintenance level does not change; and

(iv) Removing a small earthen and rock fill dam with a low hazard potential classification that is no longer needed.

(7 CFR 1b.4(d)(40))

DOE announced adoption of this categorical exclusion (formerly U.S. Forest Service categorical exclusion (e)(18)) on July 23, 2024 (89 FR 59726).

USDA-41d-USFS

Removing and/or relocating debris and sediment following disturbance events (such as floods, hurricanes, tornados, mechanical/engineering failures, etc.) to restore uplands, wetlands, or riparian systems to pre-disturbance conditions, to the extent practicable, such that site conditions will not impede or negatively alter natural processes. Examples include but are not limited to:

(i) Removing an unstable debris jam on a river following a flood event and relocating it back in the floodplain and stream channel to restore water flow and local bank stability;

(ii) Clean-up and removal of infrastructure flood debris, such as, benches, tables, outhouses, concrete, culverts, and asphalt following a hurricane from a stream reach and adjacent wetland area; and

(iii) Stabilizing stream banks and associated stabilization structures to reduce erosion through bioengineering techniques following a flood event, including the use of living and nonliving plant materials in combination with natural and synthetic support materials, such as rocks, riprap, geo-textiles, for slope stabilization, erosion reduction, and vegetative establishment and establishment of appropriate plant communities (bank shaping and planting, brush mattresses, log, root wad, and boulder stabilization methods).

(7 CFR 1b.4(d)(41))

DOE announced adoption of this categorical exclusion (formerly U.S. Forest Service categorical exclusion (e)(19)) on July 23, 2024 (89 FR 59726).

USDA-42d-USFS

Activities that restore, rehabilitate, or stabilize lands occupied by roads and trails, including unauthorized roads and trails and National Forest System roads and National Forest System trails, to a more natural condition that may include removing, replacing, or modifying drainage structures and ditches, reestablishing vegetation, reshaping natural contours and slopes, reestablishing drainage-ways, or other activities that would restore site productivity and reduce environmental impacts. Examples include but are not limited to:

(i) Decommissioning a road to a more natural state by restoring natural contours and removing construction fills, loosening compacted soils, revegetating the roadbed and removing ditches and culverts to reestablish natural drainage patterns;

(ii) Restoring a trail to a natural state by reestablishing natural drainage patterns, stabilizing slopes, reestablishing vegetation, and installing water bars; and

(iii) Installing boulders, logs, and berms on a road segment to promote naturally regenerated grass, shrub, and tree growth.

(7 CFR 1b.4(d)(42))

DOE announced adoption of this categorical exclusion (formerly U.S. Forest Service categorical exclusion (e)(20)) on July 23, 2024 (89 FR 59726).

U.S. Department of Homeland Security, U.S. Coast Guard, Categorical Exclusion

L14

~~Coast Guard~~ [N]ew construction upon, or improvement of, land where all of the following conditions are met:

(a) The structure and proposed use are substantially in compliance with prevailing local planning and zoning standards.

(b) The site is on heavily developed property and/or located on a previously disturbed site in a developed area.

(c) The proposed use will not substantially increase the number of motor vehicles at the facility.

(d) The site and scale of construction are consistent with those of existing, adjacent, or nearby buildings.

(U.S. Department of Homeland Security Instruction Manual 023-01-001-01, Revision 01, Appendix A, Table 1)

DOE announced adoption of this categorical exclusion on July 13, 2026 (https://www.energy.gov/nepa/articles/doe-adoption-us-coast-guard-cx-l14-july-13-2026).