EXHIBIT 101

Department of Energy
Washington, DC 20585

Order No. 202-26-16

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] 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 electricity, 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 and 202-25-7, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, and November 19, 2025, respectively. Subsequently, Order No. 202-25-9, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until February 17, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (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 these periods, which would help

[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/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation.
[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-9, at 3-7 (Nov. 18, 2025).

prevent the potential loss of power to homes and local 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, "[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."[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 according to a recent news report, "Holtec International expects the Palisades plant in Michigan to resume service early next year . . . ."[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 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

---

[5] *See, e.g.*, *Id.* at 7-8.

[6] *See, e.g.*, *Id.* at 8.

[7] NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025) (NERC 2025 Summer Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[8] *Id*.

[9] EIA, *Michigan State Profile and Energy Estimates* (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[10] *Id*.

[11] L.A. Times, *Nuclear plants face decadelong timeline to meet AI energy needs* (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.

into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC still anticipates "elevated risk of operating reserve shortfalls."[12]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[13] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance."[14] According to MISO, these results "reinforce the need to increase capacity."[15]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9 continue, both in the near and long term.[16] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency's data, from June 2025 through December 2025,[17] the Campbell plant has generated an average of approximately 561,100 MWh per month, 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 Central Region in response

[12] NERC 2025 Summer Reliability Assessment at 16.

[13] MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025– 2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[14] *Id.* at 12.

[15] *Id*. at 2. For further information regarding the determination that emergency conditions existed, *see Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-7 (Aug. 20, 2025).

[16] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Order No. 202-25-7 at 1, n.1.

[17] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June, July, August, September, October, November, December."* The data can then be filtered to only include the J.H. Campbell Plant.).

to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

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.[18] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[19] 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.[20]

In December of 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."[21] 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.[22] MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[23]

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*.[24] 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.

---

[18] MISO, *Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct*, FERC Docket No. ER22-495-000 (Nov. 30, 2021) (MISO Transmittal Letter). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[19] MISO Transmittal Letter at 3.

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

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

[22] *Id.* at 11.

[23] *Id.*

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

> 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.[25]

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

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[26] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[27] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[28] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[29] The 2025 NERC Long-Term Reliability Assessment 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."[30] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[31] 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."[32]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions."[33] These findings were echoed in NERC's 2024 – 2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the

---

[25] *Id.* at 12.

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

[27] *Id.* at 7.

[28] *Id.* at 8.

[29] *Id.* at 43.

[30] *Id.* at 15.

[31] *Id*.

[32] *Id*.

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

prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[34]

MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[35]

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[36]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[37] The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[38] The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[39] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[40]

---

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

[35] *See* MISO Notifications Overview, *Real-Time Operations*, https://www.misoenergy.org/markets-and-operations/notifications/.

[36] MISO 2025 – 2026 Planning Resource Auction at 13.

[37] OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation70 2311.pdf.

[38] *Id.* at 2.

[39] *Id.* at 7.

[40] *Id.* at 9.

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[41] Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[42]

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,[43] and the 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 operations.[44] 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.[45] 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, and 202-25-9 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 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

---

[41] *Id.* at 7, 9.

[42] *Id*.

[43] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[44] *Id.* P 84.

[45] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), 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. "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."

threat to our Nation's economy, national security, and foreign policy."[46] 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."[47] In a subsequent Executive Order 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."[48]

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 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."[49] 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.[50] 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 . . . ."[51]

---

[46] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[47] *Id*.

[48] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.

[49] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[50] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan* (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[51] *See* Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/.

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, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, 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."[52] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[53] 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."[54]

Pursuant to section 202(c)(4)(B) of the FPA, the Department 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 of the Department of Energy 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," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[55] 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 continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

---

[52] *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcommittee on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[53] *Id.* at 6.

[54] *Id.* at 7.

[55] 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).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9, 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 local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation until May 18, 2026.[56]

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

A. From February 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 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.

D. By March 4, 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.

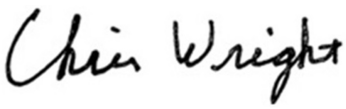
[56] 16 U.S.C. § 824a(c)(4).

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 February 17, 2026, through May 18, 2026, with the exception of applicable compliance obligations in paragraph D.



Chris Wright
Secretary of Energy

cc:

FERC Commissioners

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

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

EXHIBIT 102

Department of Energy
Washington, DC 20585

Order No. 202-26-17

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04 and 202-25-08, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain in operation for 90 days, until August 28, 2025, and November 26, 2025, respectively. Subsequently, Order No. 202-25-10, issued pursuant to FPA section 202(c), required the Eddystone Units to remain in operation for 90 days, until February 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[3] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[4] I determined that continued operation and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest.[5] My determination was based on a number of different facts.

First, in congressional testimony, PJM's President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See, e.g., PJM Interconnection, L.L.C. and Constellation Energy Corp.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).
[4] *See, e.g., id.*
[5] *See, e.g., id.* at 8, Ordering Paragraph A.

dispatchable resources, and other factors.[6] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[7] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[8] In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[9]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[10]

---

[6] *Keeping the Lights On: Examining the State of Regional Reliability: Hearing Before the Subcomm. on Energy of the H. Comm. on Energy & Com.*, 119th Cong., at 4-5 (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[7] *Id*. *See also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[8] PJM Inside Lines, *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk* (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[9] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, at 1 (Feb. 24, 2023) (Four Rs Report).

[10] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 continue, both in the near and long term.[11] The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S. Environmental Protection Agency, the Eddystone Units generated 26,971 MWh between June 2025 and December 2025,[12] providing vital generation capacity to the region. Over the summer of 2025, PJM took action to manage grid operations, issuing Hot Weather Alerts and/or Maximum Generation Alerts (Energy Emergency Alert (EEA) 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[13]

PJM's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 – February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/ Load Management Alert and an EEA 1.[14] Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) "that broadly authorizes all electric generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency."[15] The Department granted PJM's application and issued Order No. 202-26-02 on

---

[11] Further, it likely would be difficult for the oil-fired units 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. If Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

[12] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> *"2025" and "June, July, August, September, October, November, December."* The data can then be filtered to include only the Eddystone Generating Station.

[13] *See* PJM, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[14] *See id.* (search range set to: effective from 01/20/2026 until 02/07/2026).

[15] PJM, *Request for Emergency Order Under Federal Power Act, Section 202(c)*, at 2 (Jan. 24, 2026), https://www.energy.gov/documents/pjm-202c-application-2026-01-24.

January 25, 2026.[16] On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was granted by the Department on the same day.[17]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[18] PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[19] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[20]

The evidence indicates that there is also a potential longer term resource adequacy emergency in the PJM region. In a news release expressing support for Order No. 202-25-04, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[21]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[22] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for

---

[16] *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

[17] *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

[18] PJM Inside Lines, *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand* (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[19] PJM Inside Lines, *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand* (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[20] PJM Resource Adequacy Planning Special Planning Committee, *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[21] PJM Inside Lines, *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30* (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint . . . ." *Id*.

[22] Four Rs Report at 2.

renewable projects is approximately 5%.[23] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[24] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.[25]

In its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[26] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[27] PJM went on to explain that its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers," and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[28] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[29] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[30]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[31] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[32]

---

[23] *Id*.

[24] *Id.* at 16, Table 1.

[25] *Id*.

[26] PJM, *Tariff Revisions for Reliability Resource Initiative*, FERC Docket No. ER25-712, at 10 (Dec. 13, 2024).

[27] *Id*.

[28] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").

[29] *Id.* at 14.

[30] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").

[31] Affidavit of Mr. Donald Bielak at P 10.

[32] *Id.* at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[33] In its order on rehearing, FERC concluded that "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[34]

The North American Electric Reliability Corporation (NERC) has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observes that the PJM region is at high risk of energy shortfalls over the next five years[35] and faces significant reliability challenges as "[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements."[36] The assessment notes that "[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads;" however "[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays."[37] Overall, the assessment concludes that "[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements."[38]

Order Nos. 202-25-04, 202-25-08, and 202-25-10 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 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."[39] 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

---

[33] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.

[34] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

[35] NERC, *2025 Long-Term Reliability Assessment*, at 7, Figure 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[36] *Id.* at 8.

[37] *Id.* at 16.

[38] *Id.* at 91.

[39] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

commodity markets."[40] In a subsequent Executive Order 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."[41]

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 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."[42] 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. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[43] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[44] In collaboration with the national labs, the Department modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[45] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.[46]

---

[40] *Id*.

[41] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[42] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025) (Resource Adequacy Report), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[43] *See* PPL Corporation, *PPL Corporation Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINA L.pdf.

[44] *See* Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

[45] Resource Adequacy Report at 28.

[46] *Id.* at 27.

Grid operators, including PJM, have likewise acknowledged the nation's current energy crisis. For instance, during a hearing before the United States House of Representatives Committee on Energy and Commerce on March 25, 2025, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[47] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[48] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[49] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[50]

Pursuant to section 202(c)(4)(B) of the FPA, the Department 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 of the Department of Energy 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," then 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."[51] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

---

[47] Asthana Test. at 4.

[48] *Id*.

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

[50] *Id.* at 10.

[51] 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).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 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 local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the increased demand for emergency and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Eddystone Units will be available if needed to address emergency conditions, they shall remain in operation through May 24, 2026.[52]

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

A. From February 24, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

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

C. All operation of the Eddystone Units 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.

D. By March 11, 2026, PJM 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 Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this

[52] 16 U.S.C. § 824a(c)(4).

Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

E. Constellation Energy 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 Eddystone Units to comply with applicable state, local, or Federal laws 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 Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective on February 24, 2026, through May 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of February 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

EXHIBIT 103

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-18

SECOND DECLARATION OF CLINTON LAMOREAUX IN SUPPORT OF MOTION TO INTERVENE, REQUEST FOR REHEARING, AND MOTION TO STAY BY STATE OF WASHINGTON

I, Clinton Lamoreaux, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

1. I am now and at all times mentioned have been a citizen of the United States, over the age of 18 years, competent to make this declaration, and I make this declaration from my own personal knowledge and judgment.

2. I have a Bachelor of Science in Chemical Engineering, with a minor in Environmental Engineering from Colorado State University. I am a licensed professional engineer in the State of Washington.

3. I am currently employed by the Southwest Clean Air Agency (SWCAA) as the Chief Engineer. I have worked in this position since October 1, 2021. Before becoming the Chief Engineer, I worked as an Air Quality Engineer at SWCAA. I held that position from May 2000 to October 2021. Prior to working in a regulatory capacity, I worked for a company named Air Pollution Testing from May 1994 through April 2000. My duties included working with clients and regulatory personnel to devise appropriate source emissions sampling plans, coordinating and directing field sampling, and reporting results as well as training project

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

managers and technicians within the company. In cases of noncompliance, I worked with plant personnel to bring emissions within the regulatory limits. During my time at Air Pollution Testing I worked as a contractor at a variety coal-fired power plants throughout the western United States including the Centralia Plant, currently owned and operated by TransAlta Centralia Generation, LLC.

4. As the Chief Engineer at SWCAA, I supervise the engineering staff, provide technical assistance to all SWCAA staff, and continue to perform the duties of an Air Quality Engineer for several facilities, including the Centralia Plant.

5. I have been the inspector and permit writer for the Centralia Plant since 2000. My duties with respect to the Centralia Plant include conducting air quality inspections, monitoring source emissions testing, observing relative accuracy test audits of monitoring equipment, issuing Notices of Violation, and preparing New Source Review and Air Operating permits.

6. On January 13, 2026, TransAlta submitted its Air Discharge Permit Application to SWCAA. The Air Discharge Permit is a prerequisite for the repowering of Unit #2 with natural gas. Ex. 103-1 (Air Discharge Permit Application).

7. On February 25, 2026, SWCAA transmitted to TransAlta a determination that its Air Discharge Permit was missing some necessary information, including a visibility impact analysis for the Columbia River Gorge National Scenic Area, itemized retrofit costs, and elements of the best available control technology (BACT) cost analyses. Ex. 103-2 (Completeness Determination for Air Discharge Permit Application).

/ / /

/ / /

/ / /

/ / /

8. SWCAA anticipates that, depending on the outcome of the public comment process, it will issue the Air Discharge Permit for TransAlta's natural gas conversion in late summer or early fall of 2026.

DATED this 14th day of April, in Vancouver, Washington.

Clint H Lamoreaux

CLINTON LAMOREAUX

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

EXHIBIT 103-1

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Air Discharge Permit Application

TransAlta Centralia Generation, LLC

Lewis County, Washington

January 2026

Prepared for

TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

Prepared by

TETRA TECH

828 Great Northern Blvd, Suite 300
Helena, MT 59601

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table of Contents

1.0 INTRODUCTION 1-1

1.1 Regulatory Overview 1-3

1.2 Application Overview 1-3

1.2.1 Application Organization 1-3

1.2.2 Application Contacts 1-4

2.0 PROJECT DESCRIPTION 2-1

2.1 Project Summary 2-1

2.2 Description of Major Equipment 2-1

2.2.1 Unit #2 2-1

2.2.2 Auxiliary Boiler 2-1

2.2.3 Unit #2 Cooling Towers 2-2

2.2.4 Water Bath Heaters 2-2

2.3 Emissions Estimates 2-2

2.3.1 Unit #2 2-2

2.3.2 Auxiliary Boiler and Water Bath Heaters 2-3

2.3.3 Cooling Towers 2-3

2.3.4 Emissions for CTG Operations 2-4

3.0 REGULATORY APPLICABILITY EVALUATION 3-1

3.1 PSD/NSR 3-1

3.1.1 New Major Stationary Source Test 3-1

3.1.2 Major Modification Test 3-3

3.2 New Source Performance Standards (40 CFR Part 60) 3-5

3.2.1 40 CFR 60, Subpart A – General Provisions 3-5

3.2.2 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units 3-5

3.2.3 40 CFR 60, Subpart Db – Standards of Performance for Electric Utility Steam Generating Units 3-7

3.2.4 40 CFR 60, Subpart Dc – Standards of Performance for Electric Utility Steam Generating Units 3-7

3.2.5 40 CFR 60, Subpart TTTT – Greenhouse Gas Emissions for New or Modified Electric Generating Units 3-7

3.2.6 40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units 3-8
3.3 National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63) 3-8
3.3.1 40 CFR 61 – National Emission Standards for Hazardous Air Pollutants (NESHAPs) 3-8
3.3.2 40 CFR 63 – NESHAPs for Source Categories 3-9
3.4 Title V 3-9
3.5 Acid Rain Program 3-10
3.6 Greenhouse Gas Reporting Rule 3-10
3.7 State of Washington Agency Regulations 3-10
3.7.1 Air Pollution Control Authority – Powers and Duties 3-11
3.7.2 Construction of Proposed New Contaminant Sources 3-11
3.7.3 Prevention of Significant Deterioration 3-11
3.7.4 Controls for New Sources of Toxic Air Pollutants 3-11
3.7.5 Ambient Air Quality Standards 3-11
3.8 Southwest Clean Air Agency Regulations 3-12
3.8.1 General Standards for Maximum Emissions 3-12
3.8.2 Emissions Standards for Combustion and Incineration Units 3-12
3.8.3 Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants 3-12
3.8.4 Startup and Shutdown 3-12
3.8.5 Operating Permit Fees 3-13
3.8.6 Records, Monitoring and Reporting 3-13
3.8.7 Air Discharge Permit Applications 3-13
3.8.8 Application Review Process for Stationary Sources (New Source Review) 3-14
3.8.9 Requirements for New Sources in Attainment or Nonclassifiable Areas (if PSD) 3-14
4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS 4-1
4.1 Top-Down BACT Approach and Analysis Organization 4-1
4.1.1 Step 1 - Identify All Control Technologies 4-2
4.1.2 Step 2 - Eliminate Technically Infeasible Options 4-2
4.1.3 Step 3 - Rank Remaining Technologies by Control Effectiveness 4-2
4.1.4 Step 4 - Evaluate Most Effective Controls and Document Results 4-2
4.1.5 Step 5 - Select BACT 4-3
4.2 Unit #2 4-3
4.2.1 NO_x 4-3
4.2.2 CO 4-10

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

4.2.3 Particulate Matter (including PM_{10} and $PM_{2.5}$) 4-11
4.2.4 SO_2 and H_2SO_4 4-12
4.3 Auxiliary Boiler 4-12
4.3.1 NO_x 4-12
4.3.2 CO 4-14
4.3.3 Particulate Matter (including PM_{10} and $PM_{2.5}$) 4-15
4.3.4 SO_2 and H_2SO_4 4-16
4.4 Cooling Towers - 2 4-16
4.5 Water Bath Heaters - 2 4-16
5.0 TOXIC AIR POLLUTANT REVIEW 5-1
5.1 Air Toxics BACT (tBACT) 5-1
5.1.1 TAPs Chemical Classifications 5-1
5.1.2 Unit #2 5-2
5.1.3 Auxiliary Boiler 5-4
5.1.4 Cooling Towers - 2 5-4
5.1.5 Water Bath Heaters - 2 5-4
5.2 Toxic Air Pollution Impacts Review 5-5
5.2.1 Evaluating Impacts for Toxic Air Pollutants Based on Current Air Toxic Rules 5-5
5.2.2 Evaluating Impacts for Toxic Air Pollutants Based on 1998 Air Toxic Rules 5-7
5.3 Toxic Air Pollution Source Impact Analysis 5-8
5.4 Toxic Air Pollution Modeling Results 5-8
6.0 AMBIENT AIR IMPACT DEMONSTRATION/RESULTS 6-1
6.1 Introduction 6-1
6.2 Load Analysis 6-1
6.3 Secondary Pollutant Assessment 6-1
6.3.1 Secondary $PM_{2.5}$ Assessment 6-1
6.3.2 O_3 Ambient Impact Assessment 6-2
6.4 Project Impacts Compared to the SILS 6-2
6.5 NAAQS Analysis and Results 6-3
7.0 REFERENCES 7-1

List of Tables

Table 2-1. Proposed Emission Rates for Unit #2 2-3
Table 2-2. Summary of Project Emissions 2-4

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 3-1. Summary of Permitted Potential Emissions and Applicable Regulatory Thresholds 3-5
Table 3-2. State of Washington Potentially Applicable Regulations 3-11
Table 3-3. SWCAA Potentially Applicable Regulations.....3-12
Table 4-1. Unit #2 NO_x Control Technology Options and Costs, Ranked by Control Efficiency.....4-6
Table 4-2. Unit #2 CO Control Technology Options and Costs, Ranked by Control Efficiency.....4-10
Table 4-3. Auxiliary Boiler NO_x Control Technology Options and Costs, Ranked by Control Efficiency 4-13
Table 4-4. Auxiliary Boiler CO Control Technology Options and Costs, Ranked by Control Efficiency 4-15
Table 5-1. TAPs Classifications (relevant pollutants under both rules) 5-1
Table 5-2. TransAlta Project De Minimis TAP Emissions 5-6
Table 5-3. TransAlta Project SQER TAP Emissions 5-6
Table 5-4. TransAlta Project TAP Emissions for Dispersion Modeling.....5-6
Table 5-5. TransAlta Project 1998 SQER TAP Emissions 5-7
Table 5-6. TransAlta Project 1998 TAP Emissions for Dispersion Modeling 5-7
Table 5-7. TAPs Analysis Results 5-8
Table 5-8. 1998 TAPs Analysis Results 5-9
Table 6-1. SILs Analysis Results.....6-3
Table 6-2. NAAQS Analysis Results.....6-3

List of Figures

Figure 1-1. Facility Location Map 1-2
Figure 2-1. Unit #2 Process Flow Diagram 2-1

List of Appendices

Appendix A: SWCAA Application Forms
Appendix B: Emissions Calculations
Appendix C: Supporting Documentation for Regulatory Analysis
Appendix D: Supporting Documentation for BACT and tBACT analyses
Appendix E: Air Dispersion Modeling Analysis
Appendix F: Visibility Modeling Analysis

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Acronyms/Abbreviations

Acronyms/Abbreviations	Definition
ADP	Air Discharge Permit
AP-42	U.S. Environmental Protection Agency Compilation of Air Pollutant Emission Factors
ASIL	Acceptable source impact level
BACT	Best available control technology
BART	Best available retrofit technology
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DAHS	Data Acquisition and Handling System
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EU	Emissions unit
FCAA	Federal Clean Air Act
FR	Federal Register
GHG	Greenhouse gas
gr/dscf	Grains per dry standard cubic foot
HAP	Hazardous air pollutant
lb/MMBtu	Pounds per million British thermal units
lb	Pounds
lb/hr	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
N_2O	Nitrous oxide

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

NAAQS	National Ambient Air Quality Standards
NAA	Nonattainment Area
NNSR	Nonattainment Area New Source Review
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
PM	Particulate matter
PM_{10}	Particulate matter with a diameter of 10 micrometers or less
$PM_{2.5}$	Particulate matter with a diameter of 2.5 micrometers or less
PSD	Prevention of Significant Deterioration
PTE	Potential to emit
RCW	Revised Code of Washington
SO_2	Sulfur dioxide
SQER	Small quantity emissions rates
SWCAA	Southwest Clean Air Agency
TAPs	Toxic Air Pollutants
tBACT	Best Available Control Technology for Air Toxics
tpy	Tons per year
VOC	Volatile organic compounds
WDOE	Washington Department of Ecology
WAC	Washington Administrative Code

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (TransAlta) operates the Centralia electrical generation facility at the Big Hanaford site, in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at 7,500 million British Thermal Units per hour (MMBtu/hr). Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity. The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 Code of Federal Regulations, CFR, 81.327) for all pollutants.

TransAlta proposes to modify the existing Unit #2 coal-fired electrical generation facility from coal to natural gas combustion, referred to as a coal to gas (CTG) conversion (the Project). Unit #2 will cease using coal as a fuel source in December 2025. Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy for use by the customer. Unit #2 will be operated at a maximum 59% capacity factor, which may entail operating at maximum heat input for fewer hours or operating at a lower megawatt (MW) output for extended hours. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW). TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

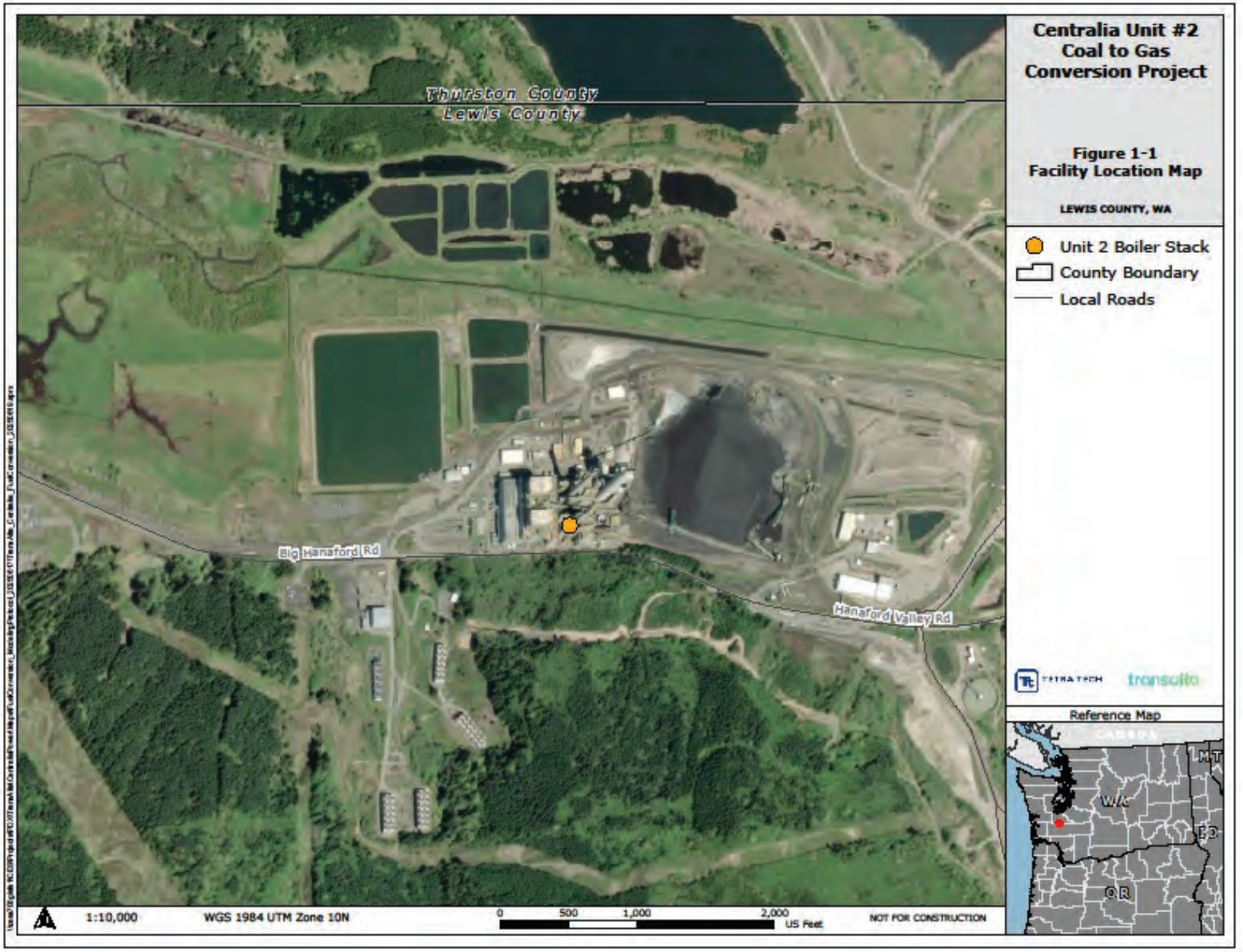
The framework and function of the boiler will remain unchanged after the conversion, including most of the existing boiler parts related to absorbing the heat from the combustion of fuels and converting it to superheated steam. To change the fuel, the burners in each corner of the boiler will be modified to create the proper mixture of natural gas and air for proper combustion.

Unit #2 will use low NO_x burners (LNB), separated overfire air (SOFA), a combustion optimization system (COS), and the Project also contemplates flue gas recirculation (FGR) to minimize formation of oxides of nitrogen (NO_x) during combustion. Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) will be controlled with good combustion practices. Particulate matter (PM), sulfur dioxide (SO_2)[1], and sulfuric acid mist (H_2SO_4) emissions will be controlled through good combustion practices and the use of clean-burning pipeline-quality natural gas.

The Project will also require replacing the existing oil-fired auxiliary boiler with a new natural gas-fired unit and ultimately replacing the existing Unit #2 cooling towers. New units associated with the modification will include natural gas-fired water bath heaters (2 -10 MMBtu/hr each).

1 Unit #2 is currently equipped with PM and SO2 controls associated with coal combustion. These controls will be removed as a part of the conversion to natural gas combustion because natural gas combustion produces far less of both pollutants than prior operations.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884



Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

1.1 Regulatory Overview

TransAlta is applying to the Southwest Clean Air Agency (SWCAA) for an Air Discharge Permit (ADP) to address the Project. Air emissions from the proposed Project primarily consist of combustion products from Unit #2. Because Lewis County is designated as unclassifiable/attainment with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants and the Facility is a major stationary source under the Prevention of Significant Deterioration (PSD) permitting program, a PSD applicability analysis is required. Based on that analysis, VOC emissions trigger PSD review requirements by exceeding its major modification significant emissions rate (SER). The other criteria pollutants do not trigger PSD and will be subject to this minor source ADP program review. Those pollutants include[2]: NO_x, CO, PM with a diameter equal to or less than 10 micrometers (PM_{10}), and PM with a diameter equal to or less than 2.5 micrometers ($PM_{2.5}$), SO_2, and H_2SO_4. The PSD program is implemented by the Washington Department of Ecology (WDOE); the ADP program is implemented by SWCAA. The required air toxics analysis is included in the ADP application because it is within the jurisdiction of the minor source permitting program. This application addresses the ADP requirements; a separate application will be submitted to WDOE to address the PSD components.

The Project will be in compliance with federal, state, and SWCAA air quality requirements including the NAAQS, WDOE AAQS, and WDOE's air toxics requirements as well as all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP).

1.2 Application Overview

1.2.1 Application Organization

This permit application is divided into seven sections. Section 1 provides an overview of the Project and regulatory requirements. Section 2 provides a detailed description of the Project, including calculated emissions. Section 3 provides a more detailed discussion of applicable regulations. Section 4 provides the Best Available Control Technology (BACT) emissions control technology evaluations for the criteria pollutants. Section 5 provides the air toxics analysis including BACT (referred to as tBACT) evaluation and first tier impacts demonstration. Section 6 provides air quality modeling analyses demonstrating compliance with the NAAQS. Section 7 provides a list of references.

The ADP application forms are included as Appendix A. Emission calculation spreadsheets providing supporting calculations for the application are provided in Appendix B. Appendix C presents supporting documents for the regulatory analysis. Appendix D presents supporting documents for the BACT and tBACT analyses. Appendix E provides the air dispersion modeling analysis including detailed emissions and stack parameter data used in the dispersion modeling, a schematic Project layout diagram and Building Profile Input Program (BPIP) model output, detailed model results, and a copy of the Project's Modeling Protocol, submitted to WDOE and SWCAA on September 26, 2025. Similarly, the visibility modeling demonstration and supporting analysis is provided in Appendix F.

[2] Greenhouse gas (GHG) emissions also fall below the SER and therefore do not trigger PSD. In addition, they are not subject to minor source permitting because GHGs are not regulated at the minor source permitting level.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

1.2.2 Application Contacts

To facilitate agency review of this application, individuals familiar with the Facility and this application are identified below.

Conrad Wieclaw
TransAlta Corporation
Phone: 360-807-8093
e-mail: Conrad_Wieclaw@transalta.com

Debbie Skibicki
Tetra Tech, Inc.
Phone: 406-437-9830
e-mail: debbie.skibicki@tetratech.com

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.0 PROJECT DESCRIPTION

2.1 Project Summary

TransAlta operates the Centralia electrical generation facility at the Big Hanaford site, in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at a nominal heat input rate of 7,500 MMBtu/hr. Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity.

The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 CFR 81.327) for all pollutants.

2.2 Description of Major Equipment

2.2.1 Unit #2

The updated Unit #2, rated at 723 megawatts (MW, net) will generate steam from natural gas combustion. The steam produced will be converted to electrical energy in the existing steam turbine. The electrical energy will be sold for use by the customer. Unit #2 will be operated at a maximum 59% capacity factor. Figure 2-1 provides the process flow diagram for Unit #2 operations.

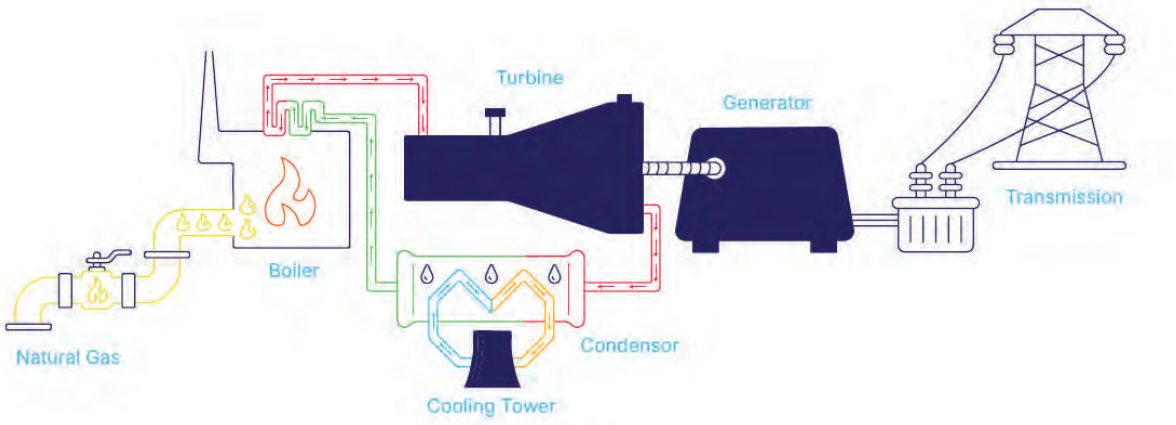


Figure 2-1. Unit #2 Process Flow Diagram

2.2.2 Auxiliary Boiler

The new auxiliary boiler will use natural gas as its sole fuel, operating as needed to keep Unit #2 warm during periods of shutdown and to provide steam to Unit #2 during startup of that unit. It also provides building heat in cold weather periods when Unit #2 is offline. The auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr and will be limited to 1,300 hours of total operation per year.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.2.3 Unit #2 Cooling Towers

The Project includes the replacement of the Unit #2 Cooling Towers with new units. Cooling towers cool the circulating water from the Unit #2 steam turbine. This cooling will be accomplished by means of two twelve-cell mechanical draft low-mist wet cooling towers, operating only when Unit #2 operates (emissions are calculated using 8,760 hours per year of operation to be conservative). A mechanical draft cooling tower will cool the circulating water by spraying the warm circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water will be entrained in this air flow; this water entrainment is called drift. Each cell of the cooling tower will be equipped with drift eliminators that are typically located above the water sprays to remove the vast majority of the entrained water droplets and return them to the fill. However, a small fraction of these droplets will escape into the fan discharge and be released to the atmosphere. The droplets that are released to the atmosphere contain dissolved solids that form particulates when the droplets evaporate and, therefore, are a source of particulate matter emissions ($PM/PM_{10}/PM_{2.5}$). The water contains no additives or cleaning products that would contribute to or produce emissions.

2.2.4 Water Bath Heaters

The Project includes two water bath heaters to heat the natural gas fuel for combustion in Unit #2 and the auxiliary boiler. Water bath heaters indirectly heat incoming gas to keep the temperature above the point where water or hydrocarbon hydrates could condense in the gas, particularly as pressure drops to meet Unit #2 and the auxiliary boiler fuel input requirements. The proposed water bath heaters are each rated at 10 MMBtu/hr and are planned to operate 8,760 hours per year.

2.3 Emissions Estimates

Emissions from the Project primarily consist of products of combustion from Unit #2. The auxiliary boiler, cooling towers, and water bath heaters are smaller sources of overall Project emissions.

2.3.1 Unit #2

As previously mentioned, Unit #2 emissions are evaluated at a maximum 59% capacity factor at full load burning natural gas. Unit #2 is also assessed at minimum stable generation (190 MW). This load scenario does not impact the potential emissions calculations but is evaluated in the air dispersion modeling analysis to ensure compliance with standards at those specific exhaust parameters.

Startup and shutdown impacts, specifically for NO_x, were evaluated for Unit #2 based on data from the current coal combustion operations. For those operations, emissions below 300 MW indicate significant lb/MMBtu variation (attributed to startups, as shutdowns tend to be a linear reduction in emissions tied to fuel usage), but on a short-term, one-hour basis. The short-term startup data is not representative of the longer term/averaged air permitting and monitoring requirements. Pursuant to Reg-27 of SWCAA Operating Permit #SW98-8-R5, NO_x emissions are evaluated on a 30-operating day rolling average including startup and shutdown emissions. Graphing the overall emissions levels over that timeframe results in a flat emissions rate under the current limit of 0.21 lb/MMBtu. Natural gas

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

combustion is anticipated to have a similar emissions profile: variation on startup, linear decreased emissions on shutdowns, and flat emissions rates over the averaging period. The lb/hr emissions rates (and associated ambient impacts) of the startup variations would fall below lb/hr emissions evaluated at 190 MW and full load because of decreased fuel usage during those time periods. TransAlta is proposing similar language for NO_x emissions limits on a 30-operating day rolling average including startup and shutdown emissions for natural gas combustion.

Beyond the combustion emissions, when Unit #2 is shutdown, there may be need for the venting of natural gas remaining in the boiler. Those emissions, listed under "shutdown methane venting" are calculated based on a worst-case 50 shutdowns per year and the anticipated venting rate. TransAlta will employ best fuel management practices to minimize the methane venting including slowing of fuel into Unit #2 if shutdown is anticipated and firing Unit #2 longer into shutdown to combust excess fuel. Methane is not a regulated pollutant under this action or under the ADP regulatory process, but the information and emissions are provided for administrative completeness.

Table 2-1 presents a summary of the proposed emissions rates for pollutants emitted from Unit #2 across the load scenarios (full load and minimum stable generation). The emissions rates listed for NO_x and CO are associated with BACT as discussed in Section 4.0. PM rates (inclusive of $PM/PM_{10}/PM_{2.5}$) are based on EPA's AP-42 – Compilation of Air Pollutant Emissions Factors from Stationary Sources (AP-42), Chapters 1.3 and 1.4 (External Combustion Sources - Fuel Oil and Natural Gas Combustion, respectively) emission factors and VOC is based on the anticipated vendor guarantee. VOC emission rates are provided for completeness in the analysis but will be evaluated separately within the PSD permitting process at WDOE.

Due to the need for a one-year "learning" period for the COS, an initial NO_x rate is proposed for this time period with a lower rate being applicable after that period ends and the COS can provide NO_x reductions.

Table 2-1. Proposed Emission Rates for Unit #2

Pollutants (lb/MMBtu)				
NOx	CO	PM	SO_2	VOC
0.11[3] 0.083	0.15	0.007	0.0007	0.003

2.3.2 Auxiliary Boiler and Water Bath Heaters

Aside from the proposed BACT NO_x and CO emissions rate for the auxiliary boiler and water bath heaters, the emissions for those units are based on AP-42, Chapter 1.4 (External Combustion Sources - Natural Gas Combustion) emission factors.

2.3.3 Cooling Towers

Cooling tower emissions are based on the concentration of the total dissolved solids in circulating water (site specific value), the drift loss of circulating water (0.0005% as proposed BACT limit), and the

[3] These NO_x rates are associated with the one-year "learning" period for the combustion optimization system. Following that year, the lower NO_x rate would apply.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

density of water. The equation used is from the South Coast Management District Cooling Tower Guidance.

2.3.4 Emissions for CTG Operations

The emissions for the proposed operations are provided in the table below. Importantly, the "Total CTG Project Emissions" line does not take into account that the Project's emissions (except VOCs) will be significantly less than the baseline of coal-fired emissions. Unit #2 CTG emissions are based on operations being limited to the annual 59% capacity factor. The overall net decrease in emissions is provided in the applicability analysis in Section 3.1.

Table 2-2. Summary of Project Emissions

TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NO_x[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.01**	**2,291,727**

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization, see discussion in Section 4.0.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3.0 REGULATORY APPLICABILITY EVALUATION

This section contains an analysis of the applicability of federal and state air quality regulations to the Facility. The specific regulations and programs that are included in this review include:

- PSD/New Source Review (NSR);
- New Source Performance Standards (NSPS);
- Federal National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Title V Operating Permits;
- Federal Acid Rain Permits;
- Federal Greenhouse Gas (GHG) Reporting Requirements;
- Other WDOE requirements; and
- Other SWCAA requirements.

3.1 PSD/NSR

In accordance with 40 CFR 52.21(2), PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area[4] and is an existing major stationary source as defined in 40 CFR 52.21(b)(1)[5]. Both the “new major stationary source” and “major modification of any existing major stationary source” analyses are provided below.

3.1.1 New Major Stationary Source Test

The Centralia Plant is a major stationary source that is currently operating. Because the Facility would need to temporarily cease operations to allow for the conversion of Unit #2 and construction of the new associated emissions units, WDOE requested discussing the United States Environmental Protection Agency’s (EPA) “Reactivation Policy.” The “Guidance on Washington State’s Prevention of Significant Deterioration Permitting Program” (WDOE PSD Guidance), Section 2.2.2.1.3 – Restarting Emissions Units states that “when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways.” Those ways include the amount of time the facility was out of operation, the reason for the shutdown, statements by the owner or operator regarding intent, and others.

WDOE PSD Guidance under “Reactivation Policy,” states the following:

> *“EPA’s policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.[6] Reactivating a “permanently” shut down source makes the source a new source under current PSD guidance. A source shutting down for more*

[4] *See, e.g.,* Air Quality Modeling Results: Levels of Sulfur Dioxide in the Ambient Air Around TransAlta Centralia Generation Power Plant (Ecology 2017).
[5] The Centralia Plant is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input which emits 100 tons per year or more of any regulated NSR pollutant.
[6] WDOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

> *than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

The WDOE PSD Guidance also states:

> *"Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[7] and is the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in its discussions with Lewis County; SWCAA, the regional air permitting authority, and WDOE in addition to vendors, customers, interested stakeholders, etc. has specifically and repeatedly expressed their intent to continue operation of the Centralia Plant as a natural gas generation resource. These plans were developed well before the anticipated end of coal combustion and will continue to build in depth and intensity through the startup of operations.

As mentioned in the WDOE PSD Guidance document, as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear –

[7] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

the Unit #2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of continued operation. This intent, along with additional EPA criteria support the conclusion that the limited shutdown of Unit #2 was "not intended to be permanent." Thus, Unit #2 is not a new source under these circumstances. The criteria are individually evaluated in a Reactivation Analysis provided in Appendix C – Supporting Documents for Regulatory Analysis.[8]

3.1.2 Major Modification Test

Pursuant to 40 CFR 52.21(b)(1), a modification of an existing major stationary source is considered a "major modification" if it results in a "a significant emissions increase… of a regulated NSR pollutant… and a significant net emissions increase of that pollutant from the major stationary source." The analysis of emissions increases is divided into two steps as described in the WDOE PSD Guidance. The first step evaluates if the change will result in a significant emissions increase of any regulated PSD pollutant, based on the application of federal regulations. If there is a significant increase in a PSD pollutant, the second step determines whether the change will result in a significant net emissions increase.

An emissions increase is significant if the increase is greater than one or more of the SERs listed in 40 CFR § 52.21(b)(23). Although EPA guidance states that both increases and decreases resulting from a project shall be accounted for under Step 1 of the applicability process,[9] also known as project emissions accounting or project netting, such accounting is explicitly prohibited under WDOE PSD Guidance. Therefore, consistent with Ecology's policy, no project netting was undertaken when calculating the baseline emissions for Unit #2.

An emissions increase is calculated by subtracting the baseline actual emissions from the projected actual emissions. Baseline emissions for any existing electric utility steam generating unit are "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project" as described in 40 CFR 52.21(b)(48). Because Unit #2 is the emissions unit being modified, the 24-month baseline period was considered specifically for that unit. The baseline period (2022-2023) chosen by TransAlta meets the criteria of being within the 5-year period immediately preceding when actual construction is anticipated to begin (2026-2027) and being representative of normal operations. Other units/equipment associated with the coal combustion operations being retired or removed are not

[8] On September 18, 2025, EPA issued an updated guidance memorandum on the "Reactivation Policy." In that guidance, EPA states that it "will no longer apply any form of the Reactivation Policy in its NSR permitting determinations and enforcement proceedings, or in its oversight of state, local and tribal air permitting programs." EPA also stated that it "will continue to apply the modification provisions of the NSR program to shut down sources in accordance with the CAA and applicable EPA regulations." The modification analysis for this project is provided in Section 3.1.2 - Major Modification Test.

[9] See discussion: Federal Register :: Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Regulations Related To Project Emissions Accounting; Withdrawal of Proposed Rule, July 21, 2025.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

included in this analysis as reductions. The projected actual emissions for Unit #2 are the future potential emissions associated with operating at the maximum annual 59% capacity factor.

Table 3-1 provides the 2022-2023 baseline for Unit #2 (as reported to and accepted by SWCAA for the criteria pollutants and EPA's GHG Reporting System for the GHGs) and the future potential emissions for Unit #2 and the other Project emissions units.[10] As previously discussed, VOC is the only pollutant that triggers PSD requirements in the first step. Because no project netting is undertaken, the second step is unnecessary and the conclusion in the first step is confirmed. A separate PSD application for VOC will be submitted to WDOE for review and processing.

[10] The above-described approach is also consistent with WDOE PSD Guidance. Baseline emissions for Unit #2 were evaluated as described/required in Section 2.2.2.2.2 of that guidance. In addition, the project emissions increase (also referred to as the "Step 1" increase) was calculated pursuant to Section 2.2.2.2.4. No netting was contemplated or requested, therefore the requirements in Section 2.2.2.2.5 - "Calculate the net emissions increase" were not applicable.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 3-1. Summary of Permitted Potential Emissions and Applicable Regulatory Thresholds

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
	(tons per year)									
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.00	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization, see discussion in Section 4.0.

As previously discussed, VOC is the only pollutant that triggers PSD requirements.

3.2 New Source Performance Standards (40 CFR Part 60)

New Source Performance Standards (NSPS) are technology-based standards applicable to new and modified stationary sources. NSPS standards were delegated to SWCAA on July 1, 2015 (and incorporated by reference pursuant to SWCAA 400-115). Several NSPS subparts apply to the Project. The following is a description of the applicable subparts, potentially applicable subparts, and the Facility's compliance with these standards.

3.2.1 40 CFR 60, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include notification of the start of construction, notification of the start of operation, performance emissions testing, monitoring, recordkeeping, and reporting.

3.2.2 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units

40 CFR 60, Subpart Da applies to each electric utility steam generating unit capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (alone or in combination with any other fuel); for which construction, modification, or reconstruction is commenced after September 18, 1978. Unit #2 has the capability of combusting more than 250 MMBtu/hr of fossil fuel; it is rated at 7,500 MMBtu/hr. The original Unit #2 was not subject to Subpart Da as construction occurred prior to the applicability date of September 18, 1978 (construction was authorized in 1969, with operation commencing in August of 1971). However, the Unit #2 CTG conversion will happen after the applicability date and must be evaluated with respect to triggering modification or reconstruction under this subpart.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Per 40 CFR 60.14, modification is considered as any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies under Section 111 of the Federal Clean Air Act. Further, no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change. None of the maximum hourly emissions rates as described above would increase for Unit #2 with the proposed change, therefore, modification under this subpart is not triggered.[11]

Per 40 CFR 60.15, reconstruction means the replacement of components of an existing facility to such an extent that:

1. The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
2. It is technologically and economically feasible to meet the applicable standards set forth in this part.

The analysis focuses on the first criteria. EPA has clarified the term “fixed capital cost” to mean “the capital needed to provide all the depreciable components and is intended to include such things as the costs of engineering, purchase, and installation of major process equipment, contractors’ fees, instrumentation...” In addition, per EPA guidance dated February 28, 2008, “Costs outside of the affected facility, such as the building, air pollution control, testing, and monitoring equipment, site preparation, removal of the old turbine, and contingency costs should not be included” in the fixed capital cost for this calculation.

As a basis, the United States Energy Information Administration (EIA) publishes capital costs associated with constructing new electrical generation facilities categorized by fuel, nominal capacity in MW, and general technology[12]. Because natural gas-fired boilers are not a listed technology[13], the closest similar unit type would be an “ultra-critical coal plant without carbon capture.” A nominal 650 MW plant today of that type at $4,103/kilowatt-net would cost $2.67 billion in 2023$ (all the dollar amounts that follow are in 2023$). In the EIA analysis, the boiler cost component is shown at $395.7 million. The total equipment cost is $997.5 million; therefore, the boiler accounts for 40% of the total equipment cost shown. Applying that percentage to the total plant cost provides a boiler cost

[11] The permitted NOx emissions rate was 0.21 lb/MMBtu over a 30-operating day average for Units 1 and 2 operating on coal (verified in a 2018 NOx stack test for Unit #2 at an hourly average of 0.22 lb/MMBtu and 1699 lb/hr). The proposed NOx emissions rate following full operations of the emissions control suite is 0.083 lb/MMBtu, also on a 30-operating day average for Unit #2, far below the previously permitted NOx limit, both in that form and if converted to a lb/hr value. In addition, as discussed with SWCAA, compliance testing performed in 2021 showed VOC test results of 0.0125 lb/MMBtu for Unit #2. VOC test results of that magnitude were also reported in 2019 for Unit #2. This short-term emissions rate exceeds the proposed natural gas VOC rate of 0.003 lb/MMBtu, both in that form and if converted to a lb/hr value.

[12] US EIA - Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies.

[13] Listed technologies for natural gas combustion include variations on simple and combined cycle combustion turbines in both simple and advanced configurations with and without carbon capture technology.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

including labor; engineering, procurement and construction (EPC) fees; contingency and owners costs of $1.07 billion. The Unit #2 boiler scope including those same components is currently estimated at approximately $173 million, equating to approximately 17% of the replacement cost. Both of those cost estimates include site preparation and contingency costs, which are calculated as a percent of the capital costs. As a result, the overall percent of replacement cost is valid without pulling out those items specifically. Therefore, Unit #2 boiler scope falls below the 50% reconstruction standard under 40 CFR 60.15(1).

Given that neither modification per §60.14 nor reconstruction per §60.15 is triggered for Subpart Da, the Unit #2 conversion is not subject to this standard.

3.2.3 40 CFR 60, Subpart Db – Standards of Performance for Electric Utility Steam Generating Units

Subpart Db applies to steam generating units with a maximum input capacity greater than 100 MMBtu/hr and less than 250 MMBtu/hr that commences construction, modification, or reconstruction after June 19, 1984. The auxiliary boiler has a maximum input capacity of 149.13 MMBtu/hr, would commence construction after the applicability date and is, therefore, subject to the standard. For a subject unit combusting natural gas with a low heat release rate, such as the auxiliary boiler, NO_x emissions are limited to 0.10 lb/MMBtu. The auxiliary boiler has a proposed NO_x emissions rate of 12 parts per million, which equates to approximately 0.015 lb/MMBtu on a rolling 30-day average. As such, the Facility meets the applicable emission limits under Subpart Db. The standard also requires a continuous emissions monitoring system (CEMS) for monitoring NO_x emissions. A continuous opacity monitoring system (COMS) is not required pursuant to §60.48b(j)(2) if records are maintained for the sulfur content of the natural gas burned (due to the low sulfur content and particulate emissions from natural gas). Similarly, as described in §60.42b(k)(2), units burning natural gas are also exempt from SO_2 limitations and monitoring requirements.

3.2.4 40 CFR 60, Subpart Dc – Standards of Performance for Electric Utility Steam Generating Units

Subpart Dc is applicable to steam generating units with a maximum heat input capacity greater than or equal to 10 MMBtu/hr and less than 100 MMBtu/hr for which construction, modification, or reconstruction is commenced after June 9, 1989. The natural gas-fired water bath heaters heat a water bath, have a maximum heat input of 10 MMBtu/hr, and would commence construction after the applicability date; therefore, the water bath heaters are subject to this standard. The standard requires initial notifications at the start of construction and at initial start-up. In addition, records must be maintained regarding the amount of fuel burned on a monthly basis. No emission or operating limits are imposed by this standard on natural gas-fired units.

3.2.5 40 CFR 60, Subpart TTTT – Greenhouse Gas Emissions for New or Modified Electric Generating Units

Subpart TTTT is applicable to electric utility generating units (EGUs) with a heat input greater than 250 MMBtu/hr of fossil fuel that serve a generator capable of selling greater than 25 MW of electricity to a utility power distribution system that commences construction on or after January 8, 2014, or

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

commenced reconstruction or modification on or after June 8, 2014. As an existing unit, Unit #2 is not currently subject to Subpart TTTT. Therefore, the requirements of Subpart TTTT can only become applicable if Unit #2 undergoes a modification or reconstruction, as defined under 40 CFR 60.14 and 60.15.

As previously discussed under Section 3.2.2 (Subpart Da), neither modification nor reconstruction has been triggered for Unit #2, therefore, Subpart TTTT is not applicable to this Project.

3.2.6 40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa applies to any steam generating unit or Integrated Gasification Combined Cycle (IGCC) unit that combusts coal and that commences modification after May 23, 2023, in addition to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in §60.5509a(a)(1) and (2).

As previously discussed under Section 3.2.2 (Subpart Da), Unit #2 will not combust coal after December 31, 2025, and thus would not be subject to the first set of applicability requirements. In addition, no stationary combustion turbines exist onsite, and none are currently planned for the site. Therefore, Subpart TTTTa is not applicable to this Project.

3.3 National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)

The Clean Air Act of 1970 required EPA to identify hazardous air pollutants (HAPs) and promulgate standards for each HAP. Between 1971 and 1990, EPA identified and published standards for eight HAPs (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride) under 40 CFR 61. The Clean Air Act Amendments of 1990 added 189 HAPs to Section 112 of the Clean Air Act and gave EPA a specific schedule to issue final standards on sources of these HAPs. EPA has published more than 100 standards under 40 CFR 63 in accordance with the Clean Air Act Amendments of 1990. The 40 CFR 61 standards are pollutant-specific, whereas the 40 CFR 63 standards are source category-specific.

3.3.1 40 CFR 61 – National Emission Standards for Hazardous Air Pollutants (NESHAPs)

3.3.1.1 40 CFR 61, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 61 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These obligations include compliance requirements; performance-based emissions testing; and monitoring, recordkeeping, and reporting requirements.

3.3.1.2 40 CFR 61, Subpart M – General Provisions

Subpart M shall apply, but not be limited to, the demolition and/or renovation of regulated asbestos containing material. The Facility will comply with this standard as applicable during the conversion of

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Unit 2 and other affected units. Further, the Facility shall comply with the provisions of SWCAA 476 "Standards for Asbestos Control, Demolition and Renovation" when conducting any renovation, demolition, or asbestos storage activities at the facility.

3.3.2 40 CFR 63 – NESHAPs for Source Categories

3.3.2.1 40 CFR 63, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 63 is also subject to the general provisions under Subpart A. Because the Facility is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include compliance dates; operation and maintenance requirements; startup, shutdown, and malfunction plans; performance emissions testing; and monitoring, recordkeeping, and reporting. The Facility has complied with and will continue to comply with the applicable requirements, performance testing, recordkeeping, and reporting outlined in Subpart A.

3.3.2.2 40 CFR 63, Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR 63, Subpart DDDDD applies to industrial, commercial, or institutional boilers or process heaters as described in §63.7485 located at a major source of HAP emissions. The Facility is a major source of HAPs. Pursuant to §63.7499 and to §63.7575, Unit #2 following CTG conversion falls into the Gas 1 subcategory of “new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.” As described by Table 3 of this subpart, the Facility must conduct a tune-up of Unit #2 annually as specified in §63.7540. In addition, Unit #2 (as an existing unit at a major source of HAPs) must have a one-time energy assessment performed by a qualified energy assessor. The specifics of that energy assessment are described in Table 3, Section 4 of Subpart DDDDD. The auxiliary boiler falls into the Gas 1 category *with* a continuous oxygen trim system and will be subject to an every-five-year tune-up requirement. The water bath heaters will be categorized when their detailed specifications are available.

3.3.2.3 40 CFR 63, Subpart UUUUU – NESHAPs for Coal- and Oil-Fired Electric Utility Steam Generating Units

40 CFR 63, Subpart UUUUU, also known as the Mercury Air Toxics Standard (MATS), previously applied to Unit #2 in the existing EGU category (specifically the “coal-fired unit not low rank virgin coal” subcategory). Pursuant to §63.9981, MATS only applies to coal-fired or oil fired EGUs as they are defined in §63.10042 of that subpart. Unit #2 firing only natural gas would no longer be subject to MATS.

3.4 Title V

Title V of the Federal Clean Air Act Amendments of 1990 sets forth operating permit requirements that apply to major sources as defined in the statute. The Air Operating Permit program is authorized under the procedures established in WAC 173-401. Several alternative criteria establish major source status, but the primary criteria that most often trigger applicability are:

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

- The facility's potential to emit any pollutant from a stationary point source is greater than 100 tpy.
- The facility's potential to emit any single listed HAP is greater than 10 tpy, or its potential to emit all HAPs combined is greater than 25 tpy.

The Centralia Plant meets the above criteria and currently holds SWCAA Air Operating Permit #SW98-8-R5, issued on October 14, 2019. The Air Operating Permit renewal application was submitted on March 15, 2023, and determined to be administratively complete on September 18, 2024, in accordance with WAC 173-401-710(1) and WAC 173-401-500.

Pursuant to WAC 173-401-500(3)(c), TransAlta will apply for a Title V modification within 12 months after commencing operation to address the requested modification.

3.5 Acid Rain Program

Unit #2 meets the definition of an affected Phase II "utility unit" under the Acid Rain Program pursuant to 40 CFR 72.6 because it is a fossil-fuel fired combustion device used to generate electricity for sale, and it serves a generator that exceeds 25 MW in capacity. Unit #2 has an existing Phase II Acid Rain Permit that has been incorporated into Centralia Plant's 40 CFR Part 70 Air Operating Permit #SW98-8-R5.

Under the Acid Rain Rule, the Centralia Plant is required to hold allowances equivalent to annual NO_x and SO_2 emissions. The Centralia Plant will amend the existing Phase II Acid Rain Permit to address the conversion of Unit #2 to natural gas combustion. That Acid Rain Permit application is included in Appendix A.

With respect to the monitoring and compliance requirements, NO_x CEMS remain a requirement under 40 CFR 75.10 and 75.12. Pursuant to 40 CFR 75.11(d), SO_2 monitoring for gas-fired units shall elect the use of SO_2 CEMS or the fuel monitoring and sulfur in fuel measurement allowed for under 40 CFR 75, Appendix D. Pursuant to 40 CFR 75.14(c) and (d), gas-fired units are exempt from the opacity monitoring provisions of Subpart 75.

3.6 Greenhouse Gas Reporting Rule

The GHG Reporting Rule (40 CFR Part 98 – Mandatory GHG Reporting) requires the reporting of specific GHG emissions by direct GHG emitters, as well as upstream indirect sources such as fossil fuel suppliers and manufacturers of heavy-duty and off-road vehicles and engines.

Electricity generation units that report CO_2 mass emissions year-round through 40 CFR Part 75 are subject to GHG reporting pursuant to 40 CFR 98.2(a)(1) and are subject to the specific provisions of 40 CFR Part 98, Subpart C. Therefore, the Centralia Plant has been reporting GHG emissions under this program since the 2010 reporting year and the Project will continue to comply with these requirements.

3.7 State of Washington Agency Regulations

In addition to regulations already discussed in preceding sections, state air regulations that pertain to the Facility are listed in Table 3-2. The rules are addressed individually in the following sections as they pertain to the Facility.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 3-2. State of Washington Potentially Applicable Regulations

Rule	Description
RCW 70A.15.2040	Air Pollution Control Authority – Powers and Duties
RCW 70A.15.2210	Construction of Proposed New Contaminant Sources
WAC 173-400-700, et seq.	Prevention of Significant Deterioration
WAC 173-460	Controls for New Sources of Toxic Air Pollutants
WAC 173-476	Ambient Air Quality Standards

3.7.1 Air Pollution Control Authority – Powers and Duties

The Revised Code of Washington (RCW) 70A.15.2040 (previously codified at RCW 70.94.141) delineates and empowers activated air pollution control authorities to develop plans for the prevention, abatement and control of air pollution within its jurisdiction. An air pollution control authority may issue such orders as may be necessary to effectuate the purposes of the Washington Clean Air Act and enforce the same by all appropriate administrative and judicial proceedings subject to the rights of appeal as provided in state law.

3.7.2 Construction of Proposed New Contaminant Sources

RCW 70A.15.2210 (previously codified at RCW 70.94.152) provides for the inclusion of conditions of operation as are reasonably necessary to assure the maintenance of compliance with the applicable ordinances, resolutions, rules and regulations when issuing Air Discharge Permits for installation and establishment of air contaminant sources.

3.7.3 Prevention of Significant Deterioration

WAC 173-400-700 through 750 includes the requirements that incorporate the federal PSD program by reference and provide authority for WDOE's State Implementation Plan (SIP)-approved PSD program. As previously mentioned, PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area and is an existing major stationary source as defined in 40 CFR 52.21(b)(1). A separate PSD application is being submitted to WDOE to address those requirements for the Facility with respect to VOC.

3.7.4 Controls for New Sources of Toxic Air Pollutants

WAC 173-460 establishes requirements for toxic air pollutants (TAPs, listed in WAC 173-460-150) including BACT for TAPs, TAPs emissions quantifications, and analysis of human health and safety protection. The TAPs BACT is included in Section 5.0, quantifications of emissions are included in Appendix B, and the impact analysis (for human health and safety) are included in Appendix E. The Project complies with the applicable TAPs standards.

3.7.5 Ambient Air Quality Standards

WAC 173-476 establishes maximum acceptable levels in the ambient air for PM/PM_{10}/$PM_{2.5}$, lead, SO_2, NO_x, O_3, and CO. The air quality of the Project site is classified as "Better than National Standards" or unclassifiable/attainment of the NAAQS for criteria pollutants (40 CFR 81.327). The air dispersion

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

modeling analysis/demonstration of compliance with these standards is provided in Section 6.0 and Appendix E.

3.8 Southwest Clean Air Agency Regulations

In addition to regulations already discussed in preceding sections, local agency air regulations that will pertain to the Project are listed in Table 3-3. The rules are addressed individually in the following sections as they pertain to the facility.

Table 3-3. SWCAA Potentially Applicable Regulations

Rule	Description
SWCAA 400-040	General Standards for Maximum Emissions
SWCAA 400-050	Emissions Standards for Combustion and Incineration Units
SWCAA 400-076	Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants
SWCAA 400-081	Startup and Shutdown
SWCAA 400-103	Operating Permit Fees
SWCAA 400-105	Records, Monitoring and Reporting
SWCAA 400-109	Air Discharge Permit Applications
SWCAA 400-110	Application Review Process for Stationary Sources (New Source Review)
SWCAA 400-113	Requirements for New Sources in Attainment or Nonclassifiable Areas

3.8.1 General Standards for Maximum Emissions

SWCAA 400-040 requires all new and existing sources and emission units to meet certain performance standards with respect to Reasonably Available Control Technology (RACT), visible emissions, fallout, fugitive emissions, odors, emissions detrimental to persons or property, sulfur dioxide, concealment and masking, and fugitive dust. The Facility will continue to comply with all the applicable requirements and general provisions in SWCAA 400-040.

3.8.2 Emissions Standards for Combustion and Incineration Units

SWCAA 400-050 requires that no person shall cause or permit the emission of particulate material from any combustion or incineration unit in excess of 0.23 grams per dry cubic meter (0.1 grains per dry standard cubic foot, gr/dscf) of exhaust gas at standard conditions. This standard is applicable to Unit #2, the auxiliary boiler, and the water bath heaters. All of the listed units have calculated PM values of approximately 0.004 gr/dscf, in compliance with this standard.

3.8.3 Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants

SWCAA 400-076 provides that if an ADP application is required under both SWCAA 400 and Chapter 173-460 WAC, then the applications shall be combined. TransAlta includes the required air toxics review and analysis in Section 5.0 in combination with the ADP application.

3.8.4 Startup and Shutdown

SWCAA 400-081 requires the consideration of any physical and operational constraints on the ability of a "stationary source" or source category to comply with the applicable technology-based standard during startup or shutdown. In addition, modeling of the emissions must consider any increase in

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

allowable emissions under startup or shutdown conditions authorized by an emission limitation or other operating parameter adopted under this rule section. Startup and shutdown impacts, specifically for NO_x, were evaluated for Unit #2 based on data from the current coal combustion operations. For those operations, emissions below 300 MW indicate significant lb/MMBtu variation (attributed to startups, as shutdowns tend to be a linear reduction in emissions tied to fuel usage), but on a short-term basis. The startup data (again, below 300 MW) was also on a one-hour basis, which is not representative of the air permitting and monitoring requirements. Pursuant to Reg-27 of SWCAA Operating Permit #SW98-8-R5, NO_x emissions are evaluated on a 30-operating day rolling average including startup and shutdown emissions. Graphing those emissions levels over that timeframe results in a flat emissions rate under the current limit of 0.21 lb/MMBtu. Natural gas combustion is anticipated to have a similar emissions profile: variation on startup, linear decreased emissions on shutdowns, and flat emissions rates over the averaging period. The lb/hr emissions rates (and associated ambient impacts) of the startup variations would fall below lb/hr emissions evaluated at 190 MW and full load because of decreased fuel usage during those time periods. TransAlta is proposing similar language for NO_x emissions limits on a 30-operating day rolling average including startup and shutdown emissions for natural gas combustion.

The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations.

3.8.5 Operating Permit Fees

SWCAA 400-103 requires the owner or operator of all "stationary sources" required to obtain an Operating Permit under 40 CFR Part 70, Chapter 173-401 WAC or RCW 70A.15.2260, to pay an annual fee as specified in this section, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the Operating Permit Program, including the fees associated with review and acting on applications and the associated application analyses. TransAlta has and will continue to pay the appropriate operating fees to SWCAA.

3.8.6 Records, Monitoring and Reporting

SWCAA 400-105 provides for all Title V stationary sources to maintain records of type and quantity of emissions, applicable emission limitations, operating limitations, and control measures. TransAlta currently maintains those calculations, records, and compliance demonstrations associated with its current Title V Operating Permit and will continue to do so under the requested permit modification.

3.8.7 Air Discharge Permit Applications

SWCAA 400-109 requires an ADP application for new construction or installation; modification, alteration or replacement of existing process or control equipment; and review of case-by-case control technology determinations (e.g., BACT) among other activities. The Project would trigger an ADP application for all of the above activities. The ADP application will be submitted with the appropriate fees as detailed in the Consolidated Fee Schedule established in accordance with SWCAA 400-098.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3.8.8 Application Review Process for Stationary Sources (New Source Review)

SWCAA 400-110 includes provisions for application completeness. Applications shall include a demonstration that all applicable emissions standards have been met (including BACT, NSPS, NESHAPs, etc.), compliance with the ambient air quality standards, and PSD applicability review. TransAlta has included the required analyses in this Section 3.1.

3.8.9 Requirements for New Sources in Attainment or Nonclassifiable Areas (if PSD)

SWCAA 400-113 provides requirements for new or modified PSD sources in an attainment or unclassifiable area. Those requirements include compliance with emissions standards, BACT, allowable impact levels, PSD applicability, toxic air pollutants (TAPs) review, and visibility analyses. The Project will meet the requirements described with respect to the PSD pollutant under review - VOC.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The Washington Clean Air Act requires all new sources and modifications which increase emissions to employ BACT. With the exception of VOC, the standard being applied in this analysis is the minor source permitting BACT as required under SWCAA 400-110(3)(c). VOC is the only pollutant triggering major source permitting under PSD pursuant to WAC 173-400-830(1)(d) and 40 CFR 52.21(j). BACT is defined in SWCAA 400-030(15) (and very similarly under 40 CFR 52.21(b)(12)) as:

> *"an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Chapter 70A.15 RCW from or which results from any new or modified "stationary source," which the Agency, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such "stationary source" or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any air pollutants which will exceed the emissions allowed under any applicable standard under 40 CFR Parts 60, 61, 62, and 63…"*

Neither the federal PSD nor the SWCAA regulations prescribe or require a procedure for conducting BACT analyses. Instead, EPA has consistently interpreted the BACT requirement as containing two core criteria: (i) the BACT analysis must include consideration of the most stringent available technologies, (i.e., those that provide the "maximum degree of emissions reduction"; and (ii) any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable.

EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached based on the environmental, energy, and economic impacts. WDOE requires the "top-down" approach for PSD BACT. That approach is followed here for VOCs.

This section will provide the basis of the analysis prior to evaluating BACT for the new or modified sources. The sources include Unit 2, the auxiliary boiler, cooling towers (2), and water bath heaters (2). The control technology analyses included in this section are organized by those emissions units and then by pollutant. This section evaluates criteria pollutants; air toxics will be evaluated in Section 5.0.

4.1 Top-Down BACT Approach and Analysis Organization

The "top down" general procedures are outlined in the *New Source Review Workshop Manual*, Office of Air Quality Planning and Standards, USEPA, Draft - October 1990. The Manual was written for use in BACT analyses under the PSD or federal NSR program. As previously discussed, with the exception of VOC, neither program is applicable to this Project. A separate PSD application for VOC has been

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

submitted to WDOE for review and processing. Nonetheless, the methodology described in the manual provides some general procedures for a BACT analysis in this instance. The methodology described in the manual consists of five basic steps, which are described below.

4.1.1 Step 1 - Identify All Control Technologies

In a complete BACT analysis, the first step is to identify all “available” control options for the emissions unit being evaluated. “Available” control options are air pollution control technologies or techniques with a practical potential for application to the emissions unit and regulated pollutant being evaluated.

4.1.2 Step 2 - Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in the first step is evaluated with respect to source-specific factors. A demonstration of technical infeasibility must be clearly documented and exhibit – based on physical, chemical, and/or engineering principles – that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are eliminated from further consideration. Note that the NSR Manual (at page B-17) states, “a source is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique or control technology. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type.”

4.1.3 Step 3 - Rank Remaining Technologies by Control Effectiveness

Available control technology options deemed technically feasible are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollutant removal value or lowest pollutant emission limit is considered the "top" control option.

4.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

The fourth step is to consider the directly associated energy, environmental, and economic impacts of the most stringent control option ascertained. Both beneficial and adverse impacts are discussed and quantified where possible.

Energy impact analyses estimate direct energy impacts of the control alternatives in units of energy consumption. Environmental impact analyses consider effects of unregulated air pollutants or non-air impacts such as liquid, solid, or hazardous waste disposal and whether they would justify selection of an alternative control option. Economic impact analyses assess costs associated with installation and operation of the various BACT alternatives.

As a guide in determining excessive control costs, alternative control systems are compared in terms of certain cost-effectiveness ratios. These ratios include the following:

- Ratio of total control costs to total investment costs;
- Cost per unit of pollution removed (for example, dollars per ton);
- Unit production costs (for example, costs per unit of product); and
- Cost per dollar of total sales.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

If energy, environmental, or economic impacts show the top control option to be infeasible, then the next most stringent alternative becomes the new top control option and is similarly evaluated. This process continues until the top control technology under consideration cannot be eliminated due to any source-specific energy, environmental, or economic impact(s).

4.1.5 Step 5 - Select BACT

The last step in evaluating BACT is to propose the most effective control option that remains after eliminating all non-viable options as part of Step 4.

4.2 Unit #2

Unit #2 currently operates as a coal-fired EGU using diesel as a startup fuel. Following the ceasing of coal combustion at the end of 2025, the Project proposes converting Unit #2 to generate electricity from natural gas. Unit #2 proposed to operate at a maximum capacity factor of 59%. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the Project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW).

Natural gas combustion produces NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and VOC. Those pollutants are subject to review under this BACT process (with the exception of VOC, which is addressed under the PSD application for BACT). GHGs, expressed as CO_{2e}, are also produced, however are not subject to BACT review as the modification of Unit #2 does not trigger PSD permitting with respect to GHG emissions. Unit #2 is evaluated as an existing source undergoing a fuel conversion; potentially applicable NSPS requirements (specifically Subpart Da) do not apply as neither modification nor reconstruction are being triggered. Therefore, new similar source installations are not comparable with respect to control technology requirements.

However, to provide a more comprehensive outline of the potential options, a review of EPA's Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emissions Rate (LAER) Clearinghouse (collectively, RBLC) was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 11.310 – Utility and Large Industrial Sized Boilers/Furnaces > 250 MMBtu/hr, Natural Gas Fired). Twelve boilers were identified between June 2017 and July 2024, all of which were smaller than Unit #2, with the largest being two units: 1,100 MMBtu/hr and 1,200 MMBtu/hr in size. In addition, nine known coal to gas converted utility boilers (units very consistent with Unit #2) were also surveyed. That information is available in Appendix D and will be discussed on a pollutant-by-pollutant basis as applicable.

4.2.1 NO_x

NO_x is formed as part of the combustion process and the NO_x compounds are generally classified in accordance with three formation mechanisms: thermal, prompt, and fuel NO_x. Thermal NO_x is formed by the thermal dissociation and subsequent reaction of nitrogen and oxygen in the combustion air at high temperature. The amount of thermal NO_x formation is a function of the boiler and burner design, flame temperature, residence time at flame temperature, and fuel to air ratios in the primary combustion zone. The rate of thermal NO_x formation increases exponentially with the flame temperature. Prompt NO_x occurs through early reactions of nitrogen molecules in the combustion air

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. Fuel NO_x is formed by the gas-phase oxidation of nitrogen that is chemically bound in the fuel. Fuel NO_x formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the amount of excess combustion air. Due to the characteristically low fuel nitrogen content of natural gas, NO_x formation through the fuel NO_x mechanism is insignificant. Consequently, the predominant type of NO_x that is formed in boilers is thermal NO_x.

Startup and shutdown impacts, specifically for NO_x, were evaluated for Unit #2 based on data from the current coal combustion operations. For those operations, emissions below 300 MW indicate significant lb/MMBtu variation (attributed to startups, as shutdowns tend to be a linear reduction in emissions tied to fuel usage), but on a short-term basis. The startup data (again, below 300 MW) was also on a one-hour basis, which is not representative of the air permitting and monitoring requirements. Pursuant to Reg-27 of SWCAA Operating Permit #SW98-8-R5, NO_x emissions are evaluated on a 30-operating day rolling average including startup and shutdown emissions. Graphing those emissions levels over that timeframe results in a flat emissions rate under the current limit of 0.21 lb/MMBtu. Natural gas combustion is anticipated to have a similar emissions profile: variation on startup, linear decreased emissions on shutdowns, and flat emissions rates over the averaging period. The lb/hr emissions rates (and associated ambient impacts) of the startup variations would fall below lb/hr emissions evaluated at 190 MW and full load because of decreased fuel usage during those time periods. TransAlta is proposing similar language for NO_x emissions limits on a 30-operating day rolling average including startup and shutdown emissions for natural gas combustion.

4.2.1.1 Step 1 – Identify All Control Technologies

There are several ways to control NO_x emissions from a boiler such as Unit #2. Some methods utilize combustion modifications that reduce NO_x formation in the boiler itself, while others utilize add-on control devices at various points in the exhaust path to remove NO_x after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NO_x. Combustion controls include low NO_x burners (LNB, including ultra-low NO_x burners), separated overfire air (SOFA), combustion optimization systems (COS), and flue gas recirculation (FGR). Add-on controls include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR).

Combustion Controls

LNBs reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. The secondary combustion zone is a fuel-lean zone where combustion is completed. LNBs may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs.

SOFA technology requires the introduction of combustion air to be separated into primary and secondary flow sections. Separation achieves complete burnout and encourages the formation of nitrogen gas (N_2) rather than NO_x. Primary air is mixed with the fuel, producing a relatively low

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

temperature, oxygen-deficient, fuel-rich zone, leading to only moderate amounts of NO_x being formed. The secondary combustion air is injected above the combustion zone through a special windbox with air-introducing ports and/or nozzles, which are mounted above the burners. Combustion is completed at this increased flame volume. As a result, the relatively low-temperature secondary stage limits the production of thermal NO_x.

COS are automated systems that adapt boiler operations and optimize combustion by dynamically regulating control variables to lower NO_x emission rates (or other pollutants) in real time using artificial intelligence. A COS was installed on Unit #2 in July 2019. Over the course of a year, the system learned to reduce NO_x emissions by 24.8% (from emissions at 133 parts per million, ppm, to 100 ppm while combusting coal).

In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. Preliminary engineering studies for the Unit #2 conversion estimate a 30.8% reduction in NO_x emissions using FGR.

Add-On or Post-Combustion Controls

SNCR is a post-combustion emissions control technology for reducing NO_x by injecting an ammonia type reactant into the boiler at a properly determined location. This technology is often used for mitigating NO_x emissions because it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. The conventional SNCR process occurs within the combustion unit, which acts as the combustion chamber. SNCR involves the noncatalytic decomposition of NO_x in the flue gas to nitrogen and water using a reducing agent (urea in this case). The reactions take place at much higher temperatures than in an SCR, typically between 1,550°F and 1,950°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_x emissions may result.

SNCR was installed on Unit #2 in 2012 to address regional haze requirements. Based on the results demonstrated from comparable units, the SNCR installation targeted a 25% reduction in NO_x emissions (and less than 5 ppm of ammonia slip). However, computational fluid dynamics modeling on Unit #2 by the SNCR manufacturer predicted a 14.9% NO_x reduction at full load and a 15.9% NO_x reduction at low load, while meeting the ammonia slip requirements. Temperature, residence time, urea distribution, and CO/O_2 distributions within the boiler impacted performance. In addition, ammonium bisulfate formation as a result of SNCR operation fouled the electrostatic precipitators, negatively impacting particulate control. The Unit #2 SNCR ultimately resulted in a 13.5% reduction in NO_x emissions over more than six years in operation. The 13.5% reduction is used in the SNCR cost per

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

ton evaluation, as it is the best information available for this specific unit. Following the installation of the COS, the SNCR ceased operation in conjunction with a 2018 agreement with SWCAA.

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia or urea is used as the reducing agent (urea is used in this analysis because the Facility already has urea storage onsite). Urea is injected into the flue gas upstream of a catalyst bed, and NO_x and ammonia combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. The control technology works best for flue gas temperatures between 575°F and 750°F (lower temperature flue gas may require preheating). Excess air is injected at the boiler exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the boiler exhaust ducting where the exhaust temperature has cooled to this temperature range. Technical factors that impact the effectiveness of this technology include inlet NO_x concentrations, the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning. The SCR reduction efficiency is based on data from the Electric Power Research Institute (EPRI) on SCR retrofits on utility boilers. The range provided in that literature was 50-80% reduction; an average value of 65% was chosen.

4.2.1.2 Step 2 – Eliminate Technically Infeasible Options

None of the previously listed control technologies are technically infeasible. Technology-specific impacts are discussed in Step 4 and include costs and emissions rates.

4.2.1.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-1. Unit #2 NO_x Control Technology Options and Costs, Ranked by Control Efficiency

Rank	Control Technology	Cost Basis	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)[14]	Annual Cost (in 2023$)[15]	Cost Effectiveness ($ per ton)
1	SCR[16]	EPA SCR Cost Data for Utility Boilers – Units 400-800 MW	65%	0.042	$46,773,453	$46,491
		EPA SCR Cost Data for Utility Boilers – Units 600-899 MW	65%	0.042	$14,954,436	$14,590

[14] The anticipated emissions rates are based on a rolling 30-day average.
[15] The equipment life and cost analyses are based on 17 years of Unit #2 operation from 2028-2044.
[16] EPA's Air Pollution Control Estimation Spreadsheet for Selective Catalytic Reduction (June 2019). Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used. The spreadsheet also takes into consideration "the estimated actual annual MWhs output." While we expect Unit #2 to operate at less then 20% capacity factor, a conservative measure of that for Unit #2 would be at 40% capacity factor. That assumption was applied to the several SCR cost estimates when calculating emissions reductions and annual operations costs. The other control technologies are based on worst-case potential emissions.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Rank	Control Technology	Cost Basis	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)[14]	Annual Cost (in 2023$)[15]	Cost Effectiveness ($ per ton)
		Vendor Estimate (preliminary)[17]	65%	0.042	$14,297,766	$13,949
		EPA Control Cost Spreadsheet	65%	0.042	$12,665,572	$12,352
2	FGR	Vendor Estimate	30.8%	0.083	$4,227,880	$5,896
3	SNCR	Actual Cost Basis	13.5%	0.104	$4,939,809	$15,730
4	LNB + SOFA +COS	--	Base Case	0.120	N/A	N/A

The control technologies are ranked by control efficiency with the "base case" being LNB, SOFA, and COS. The burners will be replaced as a part of the conversion and would be intrinsic to the boiler design, as would SOFA. As COS is already installed within Unit #2 operations and is a demonstrated NO_x reduction strategy, the COS will remain. Following conversion to natural gas combustion, the COS would retrain itself based on the new fuel combustion characteristics and air flows.

As Unit #2 is an existing unit, any changes made to the configuration or emissions control would be a retrofit. Retrofit costs included in the analysis reflect operational knowledge of the current coal-fired operations and preliminary studies on Unit #2 fired on natural gas. Economic impacts associated with the listed control options were compared using estimated annualized capital, operating, and maintenance costs. The retrofit costs are considered either in the use of the retrofit factor in the EPA control cost spreadsheets, vendor-provided cost estimates, or industry data collected by EPA for actual retrofits. Because of the capital-heavy nature of retrofit SCR installation, the SCR costs were evaluated from all those sources. The EPA SCR Cost Manual Spreadsheet calculation included a retrofit factor of 1.25, an above-average retrofit due to the extensive SCR duct and structural work anticipated given the facility building and equipment configurations.

The Unit #2 site has several aspects to it that would require significantly more costs compared to an average SCR retrofit. The most significant factor in increased retrofit cost is that the back end of Unit #2 has very little available space near the economizer for addition of major equipment. Installing an SCR in the ideal location for operational efficiency would require significant demolition of existing electrostatic precipitator (ESP) equipment and ductwork (which was planned to be left in place), as well as relocation of auxiliary equipment such as condensate tanks and possibly the induced draft (ID) fan. Due to the SCR being located further away, ductwork connecting the SCR to the flue gas path would be needed, as well as ductwork supports. Constructing these items in congested areas will be more costly than a "typical" retrofit. Since retrofit of an SCR would require extensive demolition and modification to the backend area of Unit 2, an increased outage time will be needed compared to an average retrofit. This would result in additional lost power generation revenue compared to an average retrofit.

[17] This vendor estimate is geographically specific (as in, associated with costs in western Washington) and reflects an average SCR retrofit.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

In addition to spatial related constraints, there are other areas where the Centralia plant will incur additional costs compared to an average retrofit. The Centralia plant is located in an area of elevated seismic activity and is categorized in Seismic Design Category D. All new structures, including an SCR reactor, ductwork, steel supports, CEMS building, etc., will require a higher degree of structural integrity than an average SCR retrofit, which would incur additional costs associated with materials as well as engineering and design. In order to ensure the SCR retrofit project is managed properly, the project would be executed as an engineering, procurement and construction (EPC) project, so the additional 15% (or more) contingency built in for the EPC contractor assuming overall project ownership should be considered as well. Lastly, there are some unknown costs that need to be accounted for in the retrofit factor that will require some in-depth study to determine. For example, the ID fans need to be evaluated for their ability to handle the additional pressure drop of an SCR and associated additional ductwork. The additional backpressure can be enough that the ID fan will need to be modified/replaced or booster fans with ductwork will be needed. Along with that, the draft system may require significant plant electrical distribution additions or modifications, and the cost of this should also be considered above what an average retrofit requires an increased retrofit factor is justified. These unknown costs are not included in the preliminary vendor estimate and would likely increase that estimate.

Cost calculations are available in Appendix D with the basis of all the SCR calculations provided on the last page of the EPA SCR Cost Manual Spreadsheet. In addition to the spreadsheet, EPA provided actual SCR installation capital cost data for utility boilers 699 to 800 MW in size (from 2004, appears to be mixed new installations and retrofits) and 400 to 800 MW in size (from 2012 and 2014, all retrofits) in its June 2019 SCR Cost Manual Chapter (7th edition). The average capital costs were $81 per kilowatt (kW) (in 2004$) for the first dataset and $420/kW (in 2011$) for the second. Based on those installations, Unit #2's estimated capital costs would have been between approximately $105,200,000 and $413,700,000 (both in 2023$), far exceeding the $83,438,584 in 2023$ predicted by EPA's spreadsheet (that spreadsheet includes application of the 1.25 retrofit factor).

4.2.1.4 Step 4 – Evaluate Most Effective Controls and Document Results

COS operation has resulted in increased CO emissions due to the system's optimization focus on NO_x reductions. COS also requires a one-year process learning period to analyze boiler data and optimize those operations prior to being able to effectively reduce emissions. FGR configurations also pose potential technical issues for boiler or heater burners. FGR operates by recycling flue gas and lowering the oxygen in the primary flame zone. That operation reduces NO_x emissions but may result in reduced burner capacity as the burner is less efficient with less oxygen. In addition, FGR may also result in loss of burner stability and flexibility from slowing down the combustion reaction, which in turn results in increased CO and potentially unburned hydrocarbon emissions.

SCR and SNCR both present several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In addition, SCR would require disposal or recycling of catalyst

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

materials, which may require handling in a specific landfill for hazardous waste, incurring further cost and creating waste. As previously mentioned, Unit #2's SNCR was shut off after the addition of COS exceeded NO_x controls on the unit.

While SCR is the most effective control technology, it is also clearly the most expensive at between $12,352 and $46,491 per ton of reduction. In addition, in the tightly woven configuration of Units #1 and #2, an SCR for Unit #2 would require building outside of the existing plant structure. Extensive ductwork, engineering and piping would be required for such an installation. The costs provided by the EPA SCR Cost Manual Spreadsheet are likely underestimated given the retrofit considerations, particularly in light of EPA's own actual SCR installation data mentioned above.

An SNCR system is currently installed on Unit #2 but had limited effectiveness during operation. The unit operated from 2013 through 2019, when it was turned off in favor of COS, which provided greater NO_x reductions. The inclusion of SNCR for Unit #2 post-conversion is anticipated to require relocation of all of the ammonia injection points to appropriately address the resulting fuel changes, essentially requiring a new SNCR installation.

As FGR appears to be an economically feasible option, SCNR was considered in combination with FGR and evaluated on the basis of incremental cost effectiveness. If SNCR was added following FGR, the annual cost of $4,939,809 (as shown in Table 4.1) would be associated with an additional 13.5% of control, equating to a NO_x emissions rate of 0.072 lb/MMBtu. The resulting incremental cost effectiveness would be $15,934 per ton of reduction for that combination, a high cost for a minimal reduction in emissions.

SCR was also considered in addition to FGR. The same emissions rate of 0.042 lb/MMBtu was used as the resulting SCR limit given limitations on reductions provided by SCR when used in combination with other technologies. If SCR was added following FGR, a minimal annual cost of $12,665,572 (as shown in Table 4.1, associated with the EPA Control Cost Spreadsheet) would be associated with an additional 539 tons controlled per year (at 40% capacity, see Footnote 16). The resulting incremental cost effectiveness would be $23,510 per ton for that combination, an even higher incremental cost than SNCR for an additional level of emissions reductions.

4.2.1.5 Step 5 – Select BACT

In reviewing the RBLC data of similar sources permitted over the last ten years within the PSD process, LNBs in combination with SCR are the most commonly found control method for new units. However, it is important to point out that those sources were designed with specific controls in mind and are not existing units with an existing infrastructure. To provide a better comparison, the nine known utility boilers that had converted from coal to gas (units very consistent with Unit #2 in function and size) were reviewed with respect to NO_x controls. All those units had either LNB alone or LNB in combination with overfire air with NO_x limits ranging from 0.110 to 0.137 lb/MMBtu on a rolling 30-day basis. No SCR or add-on controls were required in the known coal to gas conversions.

Based on the technical and economic analysis, TransAlta proposes the following NO_x BACT based on a one-year allowance for COS learning time using FGR, LNB, SOFA, and COS:

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

- Initial one-year learning period: 0.11 lb/MMBtu on a 30-operating day rolling average (calculated using the other control technologies without COS)
- Post one-year learning period: 0.083 lb/MMBtu on a 30-operating day rolling average.

The proposed limits include startup and shutdown.

In addition, to provide enforceability of the 40% capacity factor described in the SCR cost analysis, TransAlta proposes a natural gas combustion limitation for Unit #2 calculated using an average 40% capacity factor over 3 years of operation.

4.2.2 CO

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the inclusion or addition of NO_x control systems such as LNB, COS, and FGR may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

4.2.2.1 Step 1 – Identify All Control Technologies

As previously discussed, a review of the RBLC was conducted to identify control technologies being used for new natural gas fired boilers in addition to the known coal to gas converted boilers. The CO control technologies for the new units included catalytic oxidation on one unit, compliance with 40 CFR 63, Subpart DDDDD (the Boiler MACT rule) on two units (including the one required to use catalytic oxidation), with the remaining units listed as “good combustion practices.” None of the converted units had CO controls listed in their permits, with applications listing good combustion practices.

Good combustion practices is a general term to describe proper operation and maintenance of combustion units, which is crucial for achieving the desired air to fuel mixture and maximizing thermal efficiency. A catalytic oxidation system is a post-combustion technology that removes CO from the exhaust gas of a combustion source via incineration. CO is oxidized/converted to CO_2 and then ultimately to H_2O and CO_2 in a combustion chamber in which the CO-containing waste stream is burned. Since the inlet waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature via auxiliary fuel. In the catalytic incinerator a catalyst is used to increase the rate of the combustion reaction, allowing the combustion to occur at lower temperatures. Because the catalytic process operates at a lower temperature than the thermal process, less auxiliary fuel may be required in the catalytic process to preheat the waste gas.

4.2.2.2 Step 2 – Eliminate Technically Infeasible Options

None of the previously listed control technologies are technically infeasible. Technology-specific impacts are discussed in Step 4.

4.2.2.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-2. Unit #2 CO Control Technology Options and Costs, Ranked by Control Efficiency

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)	Annual Cost (in 2023$)	Cost Effectiveness ($ per ton)
1	Catalytic Oxidation	98%	0.003	$47,578,245	$16,724
2	Good combustion practices	Base case	0.15	N/A	N/A

The control efficiency for CO in EPA's Air Pollution Control Technology Fact Sheet for Regenerative Catalytic Oxidizers (EPA-452/F-03-021) is up to 98%; that value is used in this analysis to be conservative. Economic impacts associated with catalytic oxidation were compared using estimated annualized capital, operating, and maintenance costs[18] evaluated using that EPA spreadsheet.

4.2.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

A potential adverse environmental impact for a catalytic oxidizer results from the handling of the spent catalyst. Many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under the Resource Conservation and Recovery Act (RCRA). Costs for the installation of catalytic oxidation are high at $16,724 per ton of CO removed. This falls beyond generally acceptable dollar per ton costs for pollution control for minor source BACT analyses.

4.2.2.5 Step 5 – Select BACT

Given the consistency of requiring no add-on control for all but one unit surveyed (RBLC and conversion boilers) and the cost associated with the installation and operation of catalytic oxidation, TransAlta proposes that the use of good combustion practices coupled with the use of pipeline quality natural gas is CO BACT for Unit #2. The proposed BACT limit would be 0.15 lb/MMBtu on a 30-operating day rolling average. The proposed limit includes startup and shutdown.

4.2.3 Particulate Matter (including PM_{10} and $PM_{2.5}$)

Particulate matter (PM, including both filterable and condensable PM_{10} and $PM_{2.5}$) emissions from natural gas combustion sources consist of several components: a) inert contaminants in natural gas; b) sulfates from fuel sulfur or mercaptans used as odorants, c) dust drawn in from the ambient air, d) particulate of carbon and hydrocarbons resulting from incomplete combustion, and e) ash contained within the fuel. Units firing fuels with low ash content (such as pipeline quality natural gas) and high combustion efficiency exhibit correspondingly low particulate emissions.

Because of their extremely low particulate concentrations and resulting large costs per ton of particulate matter removed, post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have not been applied to natural gas-fired boilers in either the RBLC or the known coal to gas conversions. The use of add-on particulate control such as ESPs does not represent available control technology in use for these types of units.

TransAlta proposes that the use of good combustion practices coupled with the use of pipeline quality natural gas is PM BACT for Unit #2.

[18] Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used. The equipment life and cost analyses are based on 17 years of Unit #2 operation from 2028-2044.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

4.2.4 SO_2 and H_2SO_4

SO_2 and H_2SO_4 emissions from natural gas combustion consist of sulfates from fuel sulfur or mercaptans used as odorants. Pipeline quality natural gas has very limited sulfur content. Units firing fuels with low sulfur content exhibit correspondingly low SO_2 and H_2SO_4 emissions.

Because of their extremely low sulfur concentrations and resulting large costs per ton of SO_2 removed, post-combustion controls, such as wet or scrubbers or spray dry absorbers, have not been applied to natural gas-fired boilers in either the RBLC or the known coal to gas conversions. The add-on SO_2 controls would also control H_2SO_4. The use of add-on SO_2 control such as scrubbers does not represent available control technology in use for these types of units.

TransAlta proposes that the use of good combustion practices coupled with the use of pipeline quality natural gas is SO_2 and H_2SO_4 BACT for Unit #2.

4.3 Auxiliary Boiler

The new auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr, will be limited to 1,300 hours of total operation per year (supporting startups for Unit #2), and will fire only natural gas as fuel. Natural gas combustion produces NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2, H2SO_4, and VOCs. Those pollutants are subject to review under this BACT process. A search of EPA's RBLC was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 12.310 –Industrial Sized Boilers/Furnaces between 100 and 250 MMBtu/hr, Natural Gas Fired). However, the units surveyed did not indicate the same limited use as with the auxiliary boiler.

4.3.1 NO_x

As mentioned in the Unit #2 analysis, NO_x is formed as part of the combustion process and the NO_x compounds are generally classified in accordance with three formation mechanisms: thermal, prompt, and fuel NO_x. As prompt and fuel NO_x are negligible due to the fuel type, the predominant type of NO_x that is formed in natural gas-fired boilers is thermal NOx. The amount of thermal NO_x formation is a function of the boiler and burner design, flame temperature, residence time at flame temperature, and fuel to air ratios in the primary combustion zone. The analysis will focus on the reduction of thermal NO_x.

4.3.1.1 Step 1 – Identify All Control Technologies

There are several ways to control NO_x emissions from a boiler such as the auxiliary boiler. Some methods utilize combustion modifications that reduce NO_x formation in the boiler itself, while others utilize add-on control devices at various points in the exhaust path to remove NO_x after it is formed. The RBLC review included LNBs, FGR, and SCR for new natural gas boilers in the specified size range.

Combustion Controls

LNBs reduce NO_x by accomplishing the combustion process in stages, which partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. The secondary combustion zone is a fuel-lean zone where

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

combustion is completed. LNBs may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs.

FGR reduces NO_x emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone.

LNB and FGR are often used in conjunction on new or refurbished boilers and are shown in the RBLC as a consistent combination of controls on units of this size (and smaller); however, advancing LNB technologies (including Ultra-LNBs) may achieve similar emissions levels and FGR is often included in the general LNB configuration. Therefore, LNB is presented in general (including the potential of FGR in the boiler configuration, but not as a required element) as a base case with an estimated emissions rate of 12 ppm NO_x at 3% O_2 (0.015 lb/MMBtu), as represented in SWCAA's recently permitted NO_x requirements and in vendor quotes for industrial or commercial boiler or heater units.

Add-On or Post-Combustion Controls

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia or urea is used as the reducing agent (urea is used in this analysis because the Facility already has urea storage onsite). Urea is injected into the flue gas upstream of a catalyst bed, and NO_x and ammonia combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. The control technology works best for flue gas temperatures between 575°F and 750°F (lower temperature flue gas may require preheating). Excess air is injected at the boiler exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the boiler exhaust ducting where the exhaust temperature has cooled to this temperature range. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own. The SCR estimated control efficiency used in this analysis is based on the emissions rate permitted (0.01 lb/MMBtu) for similar units using SCR and LNB in the RBLC.

4.3.1.2 Step 2 – Eliminate Technically Infeasible Options

All of the previously listed control technologies are technically feasible.

4.3.1.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-3. Auxiliary Boiler NO_x Control Technology Options and Costs, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)[1]
1	SCR	33%	0.01
2	LNB	Base Case	0.015

1 The anticipated emissions rates are based on a rolling 30-day average.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

The costs of adding SCR to the auxiliary boiler to eliminate 0.47 tpy of NO_x would be astronomical, given the level of control proposed from the LNB. No further economic analysis is provided due to the minimal emissions from the limited use auxiliary boiler.

4.3.1.4 Step 4 – Evaluate Most Effective Controls and Document Results

Given the limited use of the auxiliary boiler, SCR as an add-on controls would be very high on a cost per ton basis. In addition, SCR presents several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH4)_2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste, incurring further cost and creating waste.

LNBs may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs even with these impacts, however, the use of a LNB is a widely used configuration for boilers of this size range.

4.3.1.5 Step 5 – Select BACT

Considering the limited use of the auxiliary boiler and consistency of LNB in boiler configurations, TransAlta proposes using LNB coupled with the NO_x limit of 12 ppm ($at\ 3\%\ O_2$, equating to 0.015 lb/MMBtu) on a rolling 30-day average as BACT for NO_x.

4.3.2 CO

As described above with respect to Unit #2, the rate of CO emissions from boilers depends on the efficiency of the fuel combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions.

4.3.2.1 Step 1 – Identify All Control Technologies

A review of the RBLC was conducted to identify control technology alternatives for the auxiliary boiler. The CO control technologies for those units included good combustion practices for all the units and catalytic oxidation for one within the search window.

Good combustion practices and design is a general term to describe proper operation and maintenance of combustion units, which is crucial for achieving the desired air to fuel mixture and maximizing thermal efficiency. A catalytic oxidation system is a post-combustion technology that removes CO from the exhaust gas of a combustion source via incineration. CO is oxidized/converted to CO_2 and then ultimately to H_2O and CO_2 in a combustion chamber in which the CO-containing waste stream is burned. Since the inlet waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature via auxiliary fuel. In the catalytic incinerator a catalyst is used to increase the rate of the combustion reaction, allowing the combustion to occur at lower temperatures. Because the catalytic

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

process operates at a lower temperature than the thermal process, less auxiliary fuel may be required in the catalytic process to preheat the waste gas.

4.3.2.2 Step 2 – Eliminate Technically Infeasible Options

Both good combustion practices and catalytic oxidation would be technically feasible.

4.3.2.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-4. Auxiliary Boiler CO Control Technology Options and Costs, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)
1	Catalytic Oxidation	98%	0.00074
2	Good combustion/design practices	Base case	0.037

The control efficiency for CO in EPA's Air Pollution Control Technology Fact Sheet for Regenerative Catalytic Oxidizers (EPA-452/F-03-021) is up to 98%; that value is used in this analysis to be conservative. However, the costs of adding catalytic oxidation to the auxiliary boiler to eliminate 3.51 tpy of CO would be extraordinarily high, given the 50 ppm (at 3% O_2) emissions level proposed for the new unit. No further economic analysis is provided due to the minimal emissions.

4.3.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

Catalytic oxidation would be the most effective control; however, it would not be economically feasible. Based on the limited use of the auxiliary boiler and the minimal emissions generated, no add-on control technology in conjunction with efficient boiler design (i.e., good combustion practices) would be economically feasible and consistent with other similar units as permitted in the RBLC. Good combustion practices is a consistent BACT requirement for natural gas boilers in this size range.

4.3.2.5 Step 5 – Select BACT

TransAlta proposes that the use of efficient boiler design/good combustion practices coupled with pipeline quality natural gas for the auxiliary boiler at a limit of 50 ppm (at 3% O_2, equating to 0.037 lb/MMBtu) as BACT for CO.

4.3.3 Particulate Matter (including PM_{10} and $PM_{2.5}$)

PM (including both filterable and condensable PM_{10} and $PM_{2.5}$) emissions from natural gas combustion sources consist of several components: a) inert contaminants in natural gas; b) sulfates from fuel sulfur or mercaptans used as odorants, c) dust drawn in from the ambient air, d) particulate of carbon and hydrocarbons resulting from incomplete combustion, and e) ash contained within the fuel. Units firing fuels with low ash content (such as pipeline quality natural gas) and high combustion efficiency exhibit correspondingly low particulate emissions. None of the RBLC boilers reviewed have controls beyond good combustion practices and pipeline quality natural gas.

Because of the extremely low particulate concentrations, large cost per ton of add-on control, and the limited use of the auxiliary boiler, TransAlta proposes using good combustion practices coupled with using pipeline quality natural gas as PM BACT for the auxiliary boiler.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

4.3.4 SO_2 and H_2SO_4

SO_2 and H_2SO_4 emissions from natural gas combustion consist of sulfates from fuel sulfur or mercaptans used as odorants. Pipeline quality natural gas has very limited sulfur content. Units firing fuels with low sulfur content exhibit correspondingly low SO_2 and H_2SO_4 emissions.

Because of the low emissions rates and the resulting large cost per ton of SO_2 and/or H_2SO_4 removed, post-combustion controls, such as wet or scrubbers or spray dry absorbers, have not been applied to natural gas-fired boilers in the RBLC. The use of add-on SO_2 control does not represent available control technology in use for these types of units.

TransAlta proposes using good combustion practices coupled with pipeline quality natural gas as BACT for SO_2 and H_2SO_4 BACT for the auxiliary boiler.

4.4 Cooling Towers - 2

PM_{10} and $PM_{2.5}$ emissions are generated from the new Unit #2 cooling towers when water droplets containing total dissolved solids are entrained in the exhaust. The sole means of controlling $PM_{10}/PM_{2.5}$ emissions from the cooling towers is the use of high-efficiency drift eliminators to minimize water droplet entrainment in the exhaust. The Project will install drift eliminators with a drift limit of no more than 0.0005 percent of the circulating water flow. With these controls, PM_{10} emissions from each cooling tower will be limited to 0.76 tpy and $PM_{2.5}$ emissions to 0.45 tpy.

TransAlta proposes that the high efficiency drift eliminators with a drift limit of no more than 0.0005 percent of the circulating water flow constitutes PM BACT for the cooling towers.

4.5 Water Bath Heaters - 2

Combustion emissions (NO_x, CO, SO_2, VOC, and $PM_{10}/PM_{2.5}$) are generated from the two water bath heaters. The units are small natural gas-fired heaters, rated at 10 MMBtu/hr each. Similar sized units permitted within SWCAA and other nearby jurisdictions have been permitted for LNB at 12 ppm NO_x and 50 ppm CO emissions rate (both at 3% O_2).

Due to their size, the pollutants generated with LNB are small with the highest criteria pollutant emission rates for each heater are 1.62 tpy of CO and 0.66 tpy of NOx. Based on the small size of the heater and the minimal emissions generated, no add-on control technology would be economically feasible (LNBs are not add-on control, they are intrinsic to boiler operation). In addition, emissions of all criteria pollutants will be minimized through combustion of pipeline quality natural gas and by following good combustion practices for these units. Therefore, TransAlta proposes LNB, the use of pipeline quality natural gas, and good combustion practices/efficient boiler design as BACT (at 12 ppm for NO_x and at 50 ppm for CO, both at 3% O_2).

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

5.0 TOXIC AIR POLLUTANT REVIEW

The Washington Clean Air Act requires all new sources and modifications which increase emissions to review and analyze TAPs as described in WAC 173-460. SWCAA also requires a TAPs analysis pursuant to the 1998 version of the WAC 173-460-080 air toxic rules. Further, SWCAA 400-076 provides that if an ADP application is required under both SWCAA 400 and Chapter 173-460 WAC, then the applications shall be combined. This section describes the TAPs analysis performed.

5.1 Air Toxics BACT (tBACT)

The Project TAP emissions were calculated within the larger emissions inventory framework. From that starting point for the current rule, the TAP potential emissions were compared to the de minimis emissions levels specified in WAC 173-460-150 (de minimis emissions levels are not provided for the 1998 air toxics rules). TAPs that exceeded the de minimis levels were analyzed further, both with respect to BACT (herein referred to as tBACT) and an acceptable source impact analysis. The acceptable source impact analysis for both sets of rules involves either comparing the increase in emissions against established small quantity emission rates (SQER) or comparing the increase in impact at any location outside of property boundaries against the Acceptable Source Impact Levels (ASILs) using air dispersion modeling. The 1998 rules have different SQER and ASIL values and in some cases, the 1998 rules regulate different TAPs than the current regulation. The ASIL demonstration was made and the first tier review was passed under both sets of rules. The modeling analysis is described in Section 5.2 and Appendix E. The tBACT analysis is covered in this section. This analysis is intended to satisfy the requirement to propose tBACT for Project emission sources that may emit TAPs.

5.1.1 TAPs Chemical Classifications

The TAP emissions that exceeded de minimis emissions levels are listed below. To appropriately evaluate emissions control across the TAPs, they were separated into chemical classifications[19] of the broader pollutant type. For example, silica and cadmium are both inorganic substances that are included in PM emissions.

Table 5-1. TAPs Classifications (relevant pollutants under both rules)

TAP	CAS Number	Classification
NO_x	10102-44-0	N/A
CO	630-08-0	N/A
SO_2	7446-09-5	N/A
H_2SO_4	7664-93-9	Acid gas
3-Methylcholanthrene	56-49-5	Organic, VOC
7,12-Dimethylbenz(a)anthracene	57-97-6	Organic, VOC
Benz(a)anthracene	56-55-3	Organic, VOC

[19] Chemical classifications, where available, were assigned based on the information provided in the Agency for Toxic Substances and Disease Registry (ATSDR) in the toxic substances portal. Other classifications are determined based on descriptions/compound summaries listed in the National Library of Medicine PubChem resource and EPA, AP-42, Tables 1.4-3, 1.4-4, 1.3-9 and 1.3-10.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

TAP	CAS Number	Classification
Benzene	71-43-2	Organic, VOC
Benzo(a)pyrene (including PAH as benzo(a)pyrene)	50-32-8	Organic, VOC
Benzo(b)fluoranthene	205-99-2	Organic, VOC
Benzo(k)fluoranthene	207-08-9	Organic, VOC
Dibenzo(a,h) anthracene	53-70-3	Organic, VOC
Dichlorobenzene	106-46-7	Organic, VOC
Formaldehyde	50-00-0	Organic, VOC
n-Hexane	110-54-3	Organic, VOC
Indo(1,2,3-cd)pyrene	193-39-5	Organic, VOC
Naphthalene	91-20-3	Organic, VOC
Toluene	108-88-3	Organic, VOC
Arsenic	7440-38-2	Metal, PM
Beryllium	7440-41-7	Metal, PM
Cadmium	7440-43-9	Metal, PM
Chromium III	7440-47-3	Metal, PM
Chromium VI	18540-29-9	Metal, PM
Cobalt	7440-48-4	Metal, PM
Copper	7440-50-8	Metal, PM
Lead	7439-92-1	Metal, PM
Manganese	7439-96-5	Metal, PM
Mercury	7439-97-6	Metal, PM
Nickel	7440-02-0	Metal, PM
Selenium	7782-49-2	Metal, PM
Vanadium	7440-62-2	Metal, PM
Silica	7631-86-9	Inorganic, PM

The individual TAPs and their chemical/pollutant classifications are evaluated on an emissions-unit basis for those TAPs that exceed the de minimis level for that unit. Note: this Project is evaluated largely as being a standalone undertaking with respect to TAPs. However, the Project is a modification of Unit #2 with the addition, replacement, and/or refurbishment of other units. Technically, a modification would address the change in emissions, not the total Project emissions. Information regarding that change in emissions is discussed under the Unit #2 analysis below.

5.1.2 Unit #2

5.1.2.1 tBACT for NO_x, CO, SO_2, and H_2SO_4 Emissions

See BACT in Section 4.0. With respect to the TAPs analysis, all of these pollutants saw significant decreases from the Unit #2 baseline; therefore, none of these pollutants are associated with an increase for the modification.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

5.1.2.2 tBACT for VOC Emissions (3-Methylcholanthrene, 7,12-Dimethylbenz-(a)anthracene, Benz(a)anthracene, Benzene, Benzo(a)pyrene [including PAH as benzo(a)pyrene], Benzo- (b)fluoranthene, Benzo(k)fluoranthene, Dibenzo(a,h)anthracene, Dichlorobenzene, Formaldehyde, n-Hexane, Indo(1,2,3-cd)pyrene, Naphthalene and Toluene)

VOC TAP emissions from natural gas combustion can come from trace amounts of VOC species in the fuel itself and from incomplete combustion of that fuel. Trace amounts of VOC species in the natural gas include formaldehyde, hexane, and benzene, all represented in the TAPs listed above. VOC TAP emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air.

VOC TAP control technologies for units reviewed in the RBLC included good combustion practices, clean fuel usage, compliance with the Boiler MACT (including boiler tune-ups), and following manufacturer specifications for startup and shutdown events. Those options can be summarized as good combustion practices overall. Optimized boiler operation minimizes emissions overall, including VOC TAPs.

Another available control technology for VOC TAPs is catalytic oxidation. Catalytic oxidation is a post-combustion technology that removes VOC TAPs from the exhaust gas of a combustion source. Those pollutants are oxidized to H_2O and CO_2 by reacting with excess air present in the boiler exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. A catalytic oxidation system was evaluated on the basis of the proportion the VOC TAPs to the overall Unit #2 TAPs. Approximately 3.30 tpy of the Unit #2 VOC emissions (58.14 tpy) or 5.7% are TAPs. Using the $47,947,931 calculated annual cost (in 2023$, see Appendix D) of adding a catalytic oxidation unit to Unit #2 as produced within the VOC BACT analysis, the cost per ton of TAPs removed would be approximately $14 million per ton of TAPs, a very high cost for emissions control particularly considering the VOC TAPs ASILs have been met.

Based on this information, TransAlta proposes that the use of good combustion practices (including compliance with the Boiler MACT) coupled with the use of pipeline quality natural gas is VOC tBACT for Unit #2.

5.1.2.3 tBACT for Metal/PM Emissions (Arsenic, Cadmium, Chromium VI, Manganese, Mercury, Nickel, and Vanadium)

The individual metals and the overall PM emissions from natural gas combustion sources primarily consist of these components: inert contaminants in the fuel, and dust drawn in from the ambient air. Add-on controls for natural gas fired boilers (i.e., fabric filter baghouses, ESPs, and particulate scrubbers) could theoretically be used but are not being used in practice for natural gas-fired in either the RBLC or the known coal to gas conversions due to the low PM emissions that extends to low metals emissions.

Based on the compliance with the ASILs without add-on controls (and the lack of add-on controls on similar units), TransAlta proposes that the use of good combustion practices coupled with the use of pipeline quality natural gas as Metals/PM tBACT for Unit #2.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

5.1.3 Auxiliary Boiler

5.1.3.1 tBACT for NO_x, CO, SO_2, and H_2SO_4 Emissions

See BACT in Section 4.0.

5.1.3.2 tBACT for VOC Emissions (7,12-Dimethylbenz(a)anthracene, Formaldehyde, and n-Hexane) and for Metal/PM Emissions (Arsenic, Cadmium, Chromium VI, Manganese, Mercury, Nickel, and Vanadium)

Both VOC and PM emissions (and their TAP components) are minimized by following good combustion and maintenance practices for natural gas fired boilers. Available controls for natural gas fired units include catalytic oxidation for volatile organic TAPs. Add-on controls for natural gas fired boilers (i.e., fabric filter baghouses, ESPs, and particulate scrubbers) could theoretically be used but are not being used in practice due to the low emissions from gaseous fuel combustion and high cost of those controls.

Annual tune-ups would also be required under the Boiler MACT. Based on limited use of the auxiliary boiler (1,300 hours per year) and the resulting minimal emissions generated, no add-on control technology would be economically feasible. TransAlta proposes good combustion practices (including compliance with the Boiler MACT) and maintaining the auxiliary boiler in accordance with manufacturers' recommendations as tBACT for the VOC and PM TAPs.

5.1.4 Cooling Towers - 2

5.1.4.1 tBACT for Inorganic/PM Emissions (Silica)

Silica is the primary component in the PM emissions generated from the new Unit #2 cooling towers when water droplets containing total dissolved solids are entrained in the exhaust.

The sole means of controlling silica/PM emissions from the cooling towers is the use of high-efficiency drift eliminators to minimize water droplet entrainment in the exhaust. The Project will install drift eliminators with a drift limit of no more than 0.0005 percent of the circulating water flow (see discussion under the PM BACT for the cooling towers) and is proposing this technology as both BACT and tBACT. This is consistent with the common BACT drift rate for other recently approved cooling towers at industrial facilities listed within the RBLC. TransAlta proposes this control technology as tBACT for silica.

5.1.5 Water Bath Heaters - 2

5.1.5.1 tBACT for NO_x Emissions

See BACT in Section 4.0.

5.1.5.2 tBACT for VOC Emissions (7,12-Dimethylbenz(a)anthracene and Formaldehyde) and Metal/PM Emissions (Arsenic, Cadmium, Chromium VI, Nickel, and Vanadium)

Both VOC and PM emissions (and their TAP components) are minimized following good combustion and maintenance practices for natural gas fired units of this size. Annual tune-ups would also be required under the Boiler MACT. Based on the small size of the heaters (10 MMBtu/hr each) and the

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

minimal emissions generated, no add-on control technology would be economically feasible. TransAlta proposes good combustion practices (including compliance with the Boiler MACT) and maintaining these units in accordance with manufacturers' recommendations as tBACT for the VOC and PM TAPs.

5.2 Toxic Air Pollution Impacts Review

The air toxics program uses a tiered review approach for regulating toxic air pollutant (TAP) emissions increases that are greater than de minimis levels. The first-tier review, outlined in WAC 173-460-080, involves evaluating the aggregate potential emissions increase of each TAP in an acceptable source impact analysis. The acceptable source impact analysis involves either comparing the increase in emissions against established small quantity emission rates (SQER) or comparing the increase in impact at any location outside of property boundaries against the Acceptable Source Impact Levels (ASILs). The current de minimis, SQER, and ASIL limits are listed in WAC 173-460-150. SWCAA additionally requires an acceptable source impact analysis to be conducted for first tier review based on the 1998 version of the WAC 173-460-080 air toxic rules. The 1998 rules have different SQER and ASIL values and do not have de minimis levels. In some cases, the 1998 rules regulate different TAPs than the current regulation. To show TAP emissions are below ASILs, dispersion modeling is required.

The first-tier review determines if the TAP source meets health-based standards without requiring additional review. If the TAP is below either the SQER or the ASIL threshold, that TAP shows an acceptable source impact and has passed the first-tier review. If compliance cannot be demonstrated in this first tier, the source may be subject to a second-tier review, which involves more detailed analysis and possibly stricter controls. A third-tier review may be conducted if further evaluation is needed.

The Project's cumulative potential increase in TAP emissions from the new and modified sources were quantified and compared to the limits in the current and 1998 version of the WAC 173-460-080 air toxics rules. It should be noted that TAP emissions reductions from past baseline operations for Unit #2 combusting coal were taken into account for NO_2, CO, SO_2, and H_2SO_4.[20] Cumulative emissions from these four TAPs will decrease as a result of the Project. Therefore, they are not included in the acceptable source impact analysis. Aside from these four TAPs, pollutant reductions from the Unit #2 baseline were not considered and the acceptable source impact analysis is expected to be a conservative proposal for certain TAPs.

5.2.1 Evaluating Impacts for Toxic Air Pollutants Based on Current Air Toxic Rules

The first-tier review of TAPs based on the current WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to de minimis thresholds. Table 5-2 shows Project TAPs that are below their respective de minimis limits. The remaining significant TAPs were then compared to the SQER thresholds.

[20] The Unit #2 emissions reductions from baseline are discussed at length in the ADP application narrative with respect to PSD applicability.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 5-2. TransAlta Project De Minimis TAP Emissions

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	De Minimis Threshold	Proposed Emissions Less than De Minimis?
Chrysene	218-01-9	lb/year	6.4E-02	4.5E-01	Yes
Toluene	108-88-3	lb/24-hr	5.7E-01	1.9E+01	Yes
Copper	7440-50-8	lb/1-hr	5.9E-03	9.3E-03	Yes
Selenium	7782-49-2	lb/24-hr	4.0E-03	7.4E-02	Yes

Table 5-3 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted.

Table 5-3. TransAlta Project SQER TAP Emissions

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	SQER Threshold	Proposed Emissions Less than SQER?
Benz(a)anthracene	56-55-3	lb/year	6.4E-02	8.9E-01	Yes
Benzo(a)pyrene	50-32-8	lb/year	4.2E-02	1.6E-01	Yes
Benzo(b)fluoranthene	205-99-2	lb/year	6.4E-02	8.9E-01	Yes
Benzo(k)fluoranthene	207-08-9	lb/year	6.4E-02	8.9E-01	Yes
Dibenzo(a,h)anthracene	53-70-3	lb/year	4.2E-02	4.1E-03	Yes
Indo(1,2,3-cd)pyrene	193-39-5	lb/year	6.4E-02	8.9E-01	Yes
Chromium III	7440-47-3	lb/24-hr	1.9E-01	3.7E-01	Yes

Table 5-4 lists the project's TAP emissions that exceed SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 5-4. TransAlta Project TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m³)
3-Methylcholanthrene	56-49-5	lb/year	6.4E-02	9.6E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	lb/year	5.7E-01	8.5E-06
Benzene	71-43-2	lb/year	1.0E+02	1.3E-01
Dichlorobenzene	106-46-7	lb/year	4.2E+01	9.1E-02
Formaldehyde	50-00-0	lb/year	8.1E+03	1.7E-01
n-Hexane	110-54-3	lb/24-hr	3.0E+02	7.0E+02
Naphthalene	91-20-3	lb/year	1.8E+02	2.9E-02
Silica	7631-86-9	lb/24-hr	4.2E+00	3.0E+00
Arsenic	7440-38-2	lb/year	8.2E+01	3.0E-04
Beryllium	7440-41-7	lb/year	5.9E+01	4.2E-04
Cadmium	7440-43-9	lb/year	7.9E+01	2.4E-04
Chromium VI	18540-29-9	lb/year	1.5E+01	4.0E-06
Cobalt	7440-48-4	lb/24-hr	1.4E-02	1.0E-01
Lead	7439-92-1	lb/year	1.9E+02	8.3E-02
Manganese	7439-96-5	lb/24-hr	5.8E-01	3.0E-01
Mercury	7439-97-6	lb/24-hr	3.0E-01	3.0E-02

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Nickel	7440-02-0	lb/year	9.6E+01	3.8E-03
Vanadium	7440-62-2	lb/24-hr	3.8E-01	1.0E-01

5.2.2 Evaluating Impacts for Toxic Air Pollutants Based on 1998 Air Toxic Rules

The first-tier review of TAPs based on the 1998 version of the WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to SQER thresholds. Table 5-5 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 5-6 lists the project's TAP emissions that exceed 1998 SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 5-5. TransAlta Project 1998 SQER TAP Emissions

Toxic Air Pollutant	CAS #	Project Potential Emissions Totals (lb/hr)	Project Potential Emissions Totals (lb/yr)	SQER Threshold (lb/hr)	SQER Threshold (lb/yr)	Proposed Emissions Less than SQER?
Naphthalene	91-20-3	4.2E-03	22	2.6	22,750	Yes
Toluene	108-88-3	2.4E-02	120	5.0	42,748	Yes
Chromium III	7440-47-3	8.0E-03	41	0.02	175	Yes
Cobalt	7440-48-4	5.8E-04	3	0.02	175	Yes
Copper	7440-50-8	5.9E-03	30	0.02	175	Yes
Lead	7439-92-1	3.5E-03	18	-	50	Yes
Manganese	7439-96-5	2.6E-03	13	0.02	175	Yes
Mercury	7439-97-6	1.8E-03	9	0.02	175	Yes
Selenium	7782-49-2	1.7E-04	1	0.02	175	Yes
Vanadium	7440-62-2	1.6E-02	81	0.02	175	Yes

Table 5-6. TransAlta Project 1998 TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m³)
Benzene	71-43-2	lb/year	7.4E+01	1.2E-01
Formaldehyde	50-00-0	lb/year	2.7E+03	7.7E-02
n-Hexane	110-54-3	lb/24-hr	3.0E+02	2.0E+02
Arsenic	7440-38-2	lb/year	7.1E+00	9.6E-05
Beryllium	7440-41-7	lb/year	4.2E-01	8.5E-06
Cadmium	7440-43-9	lb/year	3.9E+01	1.3E-01
Chromium VI	18540-29-9	lb/year	8.9E+00	9.1E-02
Nickel	7440-02-0	lb/year	7.4E+01	1.7E-01
PAH as benzo(a)pyrene	50-32-8	lb/year	7.3E-02	7.0E+02

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

5.3 Toxic Air Pollution Source Impact Analysis

Consistent with the first-tier review specified in both the current and 1998 version of WAC 173-460-080, the TAPs associated with the development of the Project and listed in Table 5-4 above were evaluated with modeling. TAPs were modeled with AERMOD for each source that emits any of the eighteen TAPs that are being evaluated under the current rule and then TAPs that are being evaluated under the 1998 rule. The AERMOD modeling was based on a unit emission rate of 1 gram/second (g/s). Then the TAP emission rates for each pollutant for each source were multiplied by modeled maximum normalized concentrations (assuming 1 g/s emission rates) and the contribution from each source summed to calculate a total impact concentration for each pollutant. This methodology is conservative because it sums all individual maximum impacts for a specific TAP for comparison with the ASIL thresholds regardless of where or when each maximum is predicted. The maximum predicted impacts from each source will likely not occur at the same time or at the same location. If this unit analysis shows noncompliance with the ASIL for any specific TAP, the TAP(s) were then modeled separately with specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact. This approach ensures that modeled impacts are not overestimated when compared to the ASIL.

5.4 Toxic Air Pollution Modeling Results

The modeling was first conducted based on a unit emission rate in a conservative unit analysis. Individual TAP modeling was conducted if the unit analysis showed noncompliance with the ASIL for any specific TAP, so as not to overestimate the TAP cumulative impacts. It should be noted that the refined receptor grid for annual impacts (see Appendix E, Figure 3-3 for receptor grid information) was incorporated into the toxics modeling and that impacts from the highest scenario for Unit #2 were included in the TAP analysis results.

Table 5-7 shows the modeling results for the eighteen TAPs modeled for the current rule compared to the current ASILs. All TAPs demonstrate compliance with their respective ASILs. Individual TAP modeling was conducted for one TAP, Chromium VI. Chromium VI was the TAP closest to their ASIL at 79%. The next TAP closest to their ASIL is Silica, at 23% of its ASIL. Additionally, Silica's impact is expected to be lower than is shown in Table 5-7 because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Table 5-7. TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
3-Methylcholanthrene	56-49-5	year	9.6E-05	4.7E-08	0%	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	year	8.5E-06	4.2E-07	5%	Yes
Benzene	71-43-2	year	1.3E-01	5.5E-05	0%	Yes
Dichlorobenzene	106-46-7	year	9.1E-02	3.1E-05	0%	Yes
Formaldehyde	50-00-0	year	1.7E-01	2.0E-03	1%	Yes
n-Hexane	110-54-3	24-hr	7.0E+02	1.5E+00	0%	Yes
Naphthalene	91-20-3	year	2.9E-02	1.6E-05	0%	Yes

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Arsenic	7440-38-2	year	3.0E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	2.4E-04	2.9E-05	12%	Yes
Chromium VI[b]	18540-29-9	year	4.0E-06	3.2E-06	79%	Yes
Cobalt	7440-48-4	24-hr	1.0E-01	6.9E-05	0%	Yes
Lead	7439-92-1	year	8.3E-02	1.3E-05	0%	Yes
Manganese	7439-96-5	24-hr	3.0E-01	3.1E-04	0%	Yes
Mercury	7439-97-6	24-hr	3.0E-02	2.1E-04	1%	Yes
Nickel	7440-02-0	year	3.8E-03	5.5E-05	1%	Yes
Vanadium	7440-62-2	24-hr	1.0E-01	1.9E-03	2%	Yes
Silica	7631-86-9	24-hr	3.0E+00	6.8E-01	23%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.
[b] Chromium VI was modeled individually with its specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact.

Table 5-8 shows the modeling results for the ten TAPs modeled for the 1998 rule compared to the 1998 ASILs. All TAPs demonstrate compliance with their respective ASILs. Chromium VI was the TAP closest to their ASIL at 8%. Note that all impacts shown in Table 5-8 are conservative because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Table 5-8. 1998 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
Benzene	71-43-2	year	1.2E-01	5.5E-05	0%	Yes
Formaldehyde	50-00-0	year	7.7E-02	2.0E-03	3%	Yes
n-Hexane	110-54-3	24-hr	2.0E+02	1.5E+00	1%	Yes
Arsenic	7440-38-2	year	2.3E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	5.6E-04	2.9E-05	5%	Yes
Chromium VI	18540-29-9	year	8.3E-05	6.6E-06	8%	Yes
Nickel	7440-02-0	year	2.1E-03	5.5E-05	3%	Yes
Vanadium	7440-62-2	24-hr	1.7E-01	1.9E-03	1%	Yes
PAH as benzo(a)pyrene	50-32-8	year	4.8E-04	3.1E-08	0%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in the 1998 version of WAC 173-460-080.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

6.0 AMBIENT AIR IMPACT DEMONSTRATION/RESULTS

The following is a summary of the air dispersion modeling analysis/ambient air quality impact demonstration and results. Detailed information on the modeling methodology is provided in Appendix E.

6.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NO_x and SO_2 emission are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NO_x and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of ultra-low sulfur diesel fuel in Unit #2. Unit #2 will now only fire natural gas.

6.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2, and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios/loads are provided in Appendix E, Attachment A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS, and toxics modeling analyses.

6.3 Secondary Pollutant Assessment

6.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Appendix E, Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

(24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NO_x and SO_2 based on EPA photochemical modeling. The most representative EPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. Section 4.3.1 of Appendix E provides the calculations used to estimate the Project-only secondary $PM_{2.5}$ impacts.

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

6.3.2 O_3 Ambient Impact Assessment

Chemical transformation of NO_x and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Appendix E, Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing EPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NOx and VOC based on the EPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the EPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NO_x emissions and 500 tpy of VOC precursor emissions. Section 4.3.2 of Appendix E provides the calculations used to estimate the Project-only secondary O_3 impacts.

6.4 Project Impacts Compared to the SILS

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 6-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 6-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 6-1. SILs Analysis Results

Pollutant	Averagng Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	98.49[c]	7.5
	Annual	H1H	1.14[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	1.86[c]	1.2
	Annual	H1H (5-year average)	0.26[c]	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	5.66 ppb[c]	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

6.5 NAAQS Analysis and Results

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Appendix E, Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and representative ambient background concentrations (as described in Appendix E, Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 6-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 6-2 are shown in contour plots provided in Attachment B of Appendix E.

Table 6-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117.98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

7.0 REFERENCES

ATSDR 2021. Toxic Substances Portal. Available online at: Substance Listing - Letter A | Toxic Substance Portal | ATSDR

EIA 2024. Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. Available online at: Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies

EPA 1990. New Source Review Workshop Manual (Draft). Available online at: NSR Workshop Manual (Draft October 1990)

EPA 2002. Air Pollution Control Technology Fact Sheet for Regenerative Catalytic Oxidizers (EPA-452/F-03-021). Available online at: Regenerative Incinerator

EPA 2019. Air Pollution Control Cost Manual, Section 4 – NOx Controls, Chapter 1 – SNCR. Available online at: Air Pollution Control Cost Manual - SNCR

EPA 2019. Air Pollution Control Cost Manual, Section 4 – NOx Controls, Chapter 2 – SCR. Available online at: Air Pollution Control Cost Manual - SCR

EPA 2024. Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers. Available online at: Incinerators and Oxidizers Calculation Spreadsheet (note: updated December 2024)

EPA 2024. Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and

Area Sources. Available online at: AP-42: Compilation of Air Emissions Factors from Stationary Sources | US EPA

EPA 2024. TANKS Emissions Estimation Software, Version 5.1 (TANKS 5.1). Available online at: TANKS Emissions Estimation Software, Version 5 | US EPA

EPA 2025. RACT/BACT/LAER Clearinghouse (RBLC). Available online at: Clean Air Technology Center | US EPA

EPRI 2000. Retrofit NOx Controls for Coal-Fired Utility Boilers - 2000 Update. Available online at: EPRI Retrofit NOx Controls for Coal-Fired Utility Boilers

National Library of Medicine 2025. PubChem Resource. Available online at: PubChem

South Coast Air Quality Management District 2019. Guidelines for Calculating Emissions from Cooling Towers. Available online at: 2019_1100_SCAQMD_GuidelinesCoolingTowers.pdf

TCEQ 2019. BACT Guidelines for Chemical Sources. Available online at: BACT Guidelines for Chemical Sources - Texas Commission on Environmental Quality - www.tceq.texas.gov

WDOE 2010 (rev 2015). Guidance Document: First, Second, and Third Tier Review of Toxic Air Pollutant Sources. Available online at: Guidance Document: First, Second, and Third Tier Review of Toxic Air Pollution Sources

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

WDOE 2017. Guidance on Washington State's Prevention of Significant Deterioration Permitting Program. Available online at: Guidance on Washington State's Prevention of Significant Deterioration Permitting Program

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX A: SWCAA APPLICATION FORMS

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Southwest Clean Air Agency

5101 NE 82nd Ave., Vancouver, WA 98662 Phone: (360) 574-3058

PERMIT APPLICATION

TOTAL ENCLOSED FEE: $ 9,964 (to be submitted with application, no fee required for change of location or change of registered owner)
If you want this permit application to be expedited, have you **doubled the fee**? ☐ YES ■ NO

See Consolidated Fee Schedule (Table 2 or 9)

COMPANY INFORMATION

NAME OF APPLICANT	STREET	CITY	STATE	ZIP	PHONE	E-MAIL
TransAlta Centralia Generation, LLC, 913 Big Hanaford Road, Centralia, WA 98531					(360)807-8093	conrad_wieclaw@transalta.com

LEGAL NAME OF BUSINESS FOR WHICH APPLICATION APPLIES	PHONE	E-MAIL
TransAlta Centralia Generation, LLC	(360)807-8093	conrad_wieclaw@transalta.com

STREET	PO BOX	CITY	COUNTY	STATE	ZIP
913 Big Hanaford Road, Centralia, Lewis County, WA 98531					

TYPE OF ORGANIZATION

☐ CORPORATION ■ LIMITED PARTNERSHIP ☐ GOVERNMENT ENTITY
☐ INDIVIDUAL (Sole Proprietorship) ☐ GENERAL PARTNERSHIP ☐ OTHER _____

ARE ALL FACILITIES, UNDER THE SAME OWNERSHIP IN WASHINGTON, IN COMPLIANCE WITH FEDERAL, STATE, AND LOCAL AIR POLLUTION REGULATIONS? ■ YES ☐ NO

ARE YOU THE OWNER OF THE EQUIPMENT UNDER THIS APPLICATION? ■ YES ☐ NO OWNER IDENTIFICATION NUMBER

IF NO, ENTER LEGAL NAME OF OWNER: _____ ☐ S.S. NUMBER

☐ UBI No.

FACILITY INFORMATION

FACILITY NAME	EQUIPMENT ADDRESS / LOCATION Street	City	County	State	Zip
TransAlta Centralia Plant	913 Big Hanaford Road, Centralia, Lewis County, WA 98531				

MAILING ADDRESS Street	City	State	Zip	FACILITY OPERATING SCHEDULE
913 Big Hanaford Road, Centralia, Lewis County, WA 98531				hrs/day varies days/wk _____ wks/yr _____

CONTACT PERSON AND TITLE	PHONE	E-MAIL
Conrad Wieclaw	(360)807-8093	conrad_wieclaw@transalta.com

NAICS Code
221112

IS THERE A SCHOOL OR DAYCARE WITHIN 1000 FT OF THIS FACILITY? ☐ YES ☑ NO

CONTROL EQUIPMENT INFORMATION

EQUIPMENT DESCRIPTION
Conversion of Unit #2 from coal to natural gas combustion, replacement of aux boiler and cooling towers, adding water bath heaters

APPLICATION FOR:

☐ New Construction or Installation ☑ Modification or Alteration of Equipment ☐ Change of Location
☐ Change of Approval Condition ☐ Change of Registered Owner ☐ Other _____
☐ Existing Equipment Operating Without Approval ☐ Existing Equipment With Expired or Lapsed Approval or Registration
Has a Notice of Violation been Issued? ☐ Yes ■ No If Yes, Number: _____

ESTIMATED COST:
For Total Modification / New Facility: _____ For Air Pollution Control Equipment: _____

ESTIMATED INSTALLATION START DATE: 2026 **ESTIMATED COMPLETION DATE:** 2027

DO YOU CLAIM CONFIDENTIALITY OF INFORMATION? ☐ YES ■ NO (Each page with confidential information must be clearly marked in red)

I do hereby certify that the information contained in this PERMIT APPLICATION is, to the best of my knowledge, accurate and complete.

Signature: Signed by: Conrad Wieclaw 130F85AFA0D714B4... Title: Engineering and Environmental Manager Date: 13 January 2026 | 9:05 AM MS

AGENCY USE ONLY

SWCAA ID #: _____ Expedited Application: ☐ YES ☐ NO

Application Fee: _____ Date: _____ Application #: _____

Review/Add'l Fees: _____ Date: _____ SIC/NAICS #: _____

AGENCY USE ONLY

Date Stamp

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Southwest Clean Air Agency

Notice of Construction Attachment

INDUSTRIAL FIELD ASSEMBLED BOILER INFORMATION

TransAlta Centralia Generation, LLC
Parent Company Name

TransAlta Centralia Plant
Plant Name

I. General (check appropriate square(s)): **Unit #2 Boiler Coal to Gas Conversion**

A. Service Conditions: Details:

☑Power Generation **Unit #2 (723 MW) will operate at a maximum 59% capacity factor to generate electricity**
☐ Process Steam
☐ Waste Heat Recovery
☐ Chemical Recovery
☐ Incineration Features
☐ Space Heat
☐ Other

B. Description:

1. Manufacturer:
2. Type and Model No.:
3. Fuel Heat Input: **7,500 MMBtu/hr** (Btu/hr)
4. Fuel Heating Value : **1107 Btu/ft³** (Btu/lb or Btu/ft^3)
5. Installation Date: **1971**
6. Dates of Major Rebuilds:
7. Dates of Major Revisions: **Proposed for 2026-2027**
8. Drawings:

C. Characteristics:

☐ Fire Tube
☐ Water Tube
☐ Straight Tube
☐ Bent Tube

D. Firing

☐ Dry Bottom
☐ Wet Bottom
☐ Fluidized Bed
☐ Dutch Oven
☐ Direct-Fired Solid Fuel
☐ Single-Fuel Burner(s)
☐ Combination Burner(s)

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

☐ Mechanical Atomization ☐ Steam Atomization
☐ Rotary Cup ☐ Air Atomization
☐ Other_____

Stoker-Fed:

☐ Over-Fed: ☐ Traveling Grate
☐ Shaker Grate
☐ Stationary Grate

☐ Under-Fed
☐ Spreader
☐ Hand

Geometry:

☐ Cyclonic
☐ Tangential
☐ Direct Entry
☐ Other_____

Combustion Air:	Point(s) of Introduction:	Temperatures: Preheated ☐
☐ Primary	_____	_____
☐ Secondary	_____	_____
☐ Tertiary	_____	_____
☐ Other	_____	_____

II. Ratings:

A. Steam Generation (lb/hr):

1. Average Design Load Conditions: _____@ _____PSIG & _____°F

2. Rated Boiler Capacities, Burning: _____(Fuels:)_____

(_____)(_____)(_____)(_____)

a. Continuous _____

b. Peaking Rate (lb/hr) Time Period

_____ _____
_____ _____

3. Turn-Down: _____
_____
_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

B. Performance:

1. Inputs-1,000 Btu/hr (HHV): _____(Fuels:)_____

(_____)(_____)(_____)(_____)

2. Efficiencies: _____
   a. Over-all, _____
   at conditions: _____

   b. A.S.M.E. Short-form (for units >250 mmBtu/hr input)

	Btu/lb Fuel Fired
(1) Energy absorbed by boiler fluid:	_____
(2) Energy loss due to dry flue gases:	_____
(3) Energy loss due to moisture in fuel:	_____
(4) Energy loss due to evaporating and superheating moisture formed by combustion of hydrogen:	_____
(5) Energy loss due to incomplete combustion of carbon to CO:	_____
(6) Energy loss due to combustible in refuse:	_____
(7) Energy loss due to radiation and unaccounted for:	_____

(Based on_____(Btu/lb) for_____)

3. Applicable NSPS: ***NSPS not applicable (see discussion in Section 3.0 of Application)***

☐ 40 CFR 60.40 (Subpart D) >250 mmBtu/hr constructed/modified after 8/17/71
☐ 40 CFR 60.40a (Subpart Da) >250 mmBtu/hr constructed/modified after 9/18/78
☐ 40 CFR 60.40b (Subpart Db) ≥100 and ≤250 mmBtu/hr constructed/modified after 6/19/84
☐ 40 CFR 60.40c (Subpart Dc) ≥10 and <100 mmBtu/hr constructed/modified after 6/9/89

4. NSPS Emission Limits:

SO_2	NO_x as NO_2	PM	PM_{10}	CO	VOC
_____	_____	_____	_____	_____	

☑ CEM required ***(for Acid Rain, not NSPS***), which pollutants: ☐ SO_2 ☑ NO_x ☐ PM ☐ CO
☐ _____
☐ _____

III. Physical Description:

A.	Furnace Parameters (as applicable)	Dutch Oven Parameters (as applicable)
1. Reference Drawings:	_____	_____
2. Dimensions:	_____	_____
3. Grate Area:	_____	_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

4. Water Cooled Surfaces---
Descriptions and square feet:

a. _____ _____
_____ _____

b. _____ _____
_____ _____

c. _____ _____
_____ _____

5. Combustion Air Controls---
Describe _____ _____
_____ _____

6. Burner Specifications:

Type, Make, Model #	Fuel Fired	Rating (Btu/hr)	Number Installed
a. _____	_____	_____	_____
_____	_____	_____	_____
b. _____	_____	_____	_____
_____	_____	_____	_____
c. _____	_____	_____	_____
_____	_____	_____	_____

7. Stoker Specifications (as appropriate):

a. _____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____
b. _____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____

8. Reinjection Details: _____

_____

_____

_____

9. Combustion Control (see also Section III-F):

a. Description: _____

_____

_____

b. Schematic Drawings: _____

_____

_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

10. Ash Removal:

a. Description of Method(s):

(1) _____

_____

(2) _____

_____

B. Evaporative Sections (in addition to area previously noted):

1. Convection Area: Surface Area (ft^2)

a. First Pass _____
b. Second Pass _____
c. Third Pass _____
d. Other (specify as fire tube, etc.)
_____ _____

2. Screen: _____
3. Superheater:

a. Radiant _____
b. Convection _____

4. Reheat _____

5. Economizer _____

6. Other (specify): _____

C. Soot Blowers:

1. Type, Make Model No.	Location	Number
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

2. Operating Schedule(s):

_____

_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3. Boiler Conditions While Operating:

D. Steam Drums:

Designation	Inside Dimensions	Number

E. Draft Side Equipment:

1. Air Preheater(s): Type, Make, Model No. Ratings

a. _____ _____

_____ _____

b. _____ _____

_____ _____

2. Fans: Ratings (max. design) Drive

CFM @ S.P. & Gas Conditions Description (Horse Power)

a. Forced Draft:

(1) Maximum: _____ _____

Design: _____ _____

(2) Type, Make, Model: _____ _____

_____ _____

_____ _____

b. Induced Draft:

(1) Maximum: _____

Design: _____

(2) Type, Make, Model: _____ _____

_____ _____

_____ _____

c. Other (specify): _____

(1) Maximum: _____ _____

Design: _____ _____

_____ _____

(2) Type, Make, Model: _____ _____

_____ _____

_____ _____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3. Stack: Height **460 feet** Inside Diameter **24 feet**

   a. Configuration: _____ _____

   b. Sampling Ports: Location Number Access Description

   _____ _____ _____
   _____ _____ _____
   _____ _____ _____

   c. Other Units Connected to Stack (list):

   _____
   _____
   _____

   d. Bypass Capability - explain:

   _____
   _____
   _____

F. Instrumentation and Control:

Gage or Meter	Controller/ Recorder	Manual	Auto	Schematic Reference
1. Feed Water: _____				
2. Draft: (note)				
3. Fuel: (note)				
4. Steam Flow: _____				

5. Flue Gas, Temperature, Emission Control, etc.: (note) ***see Appendix E for modeling parameters***

a. _____		
b. _____		
c. _____		
d. _____		
e. _____		
f. _____		
g. _____		
h. _____		

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

IV. Operating Parameters:

A. Fuels Burned (list): **Natural gas**

1. Maximum Rate: _____
(_____)(_____)(_____)(_____)
2. Higher Heating Value (BTU/same units as above): **1107 Btu/scf**
3. Proximate Anal. (as received): Average Maximum

a. Moisture _____ _____
b. Ash _____ _____

4. Ultimate Analysis: (wt.%, dry basis)

a. Sulfur _____ _____
b. Hydrogen _____ _____
c. Carbon _____ _____
d. Nitrogen _____ _____
e. Oxygen _____ _____

B. Operating Schedule:

1. Anticipated % of Annual Through-Put (by quarter):

Fuel:				
Period:				
Dec-Feb				
Mar-May				
Jun-Aug				
Sep-Nov				

2. Normal Schedule:

Period:	Hrs/Day	Days/Wk	Wks/Period
Dec-Feb			
Mar-May			
Jun-Aug			
Sep-Nov			

3. Scheduled Shut-Downs:

_____

_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

C. Gas Profiles (Please complete where data is readily obtainable or reasonably estimated. Underline all estimated values. Note that the profile desired is for maximum average firing conditions with the most likely fuel inputs.): ***See emissions inventory information in Appendix B.***

Firing conditions for following profile:_____

_____

_____

	Temp. (°F)	Velocity (FPM)	Flow Rate (ACFM)	Static Press ("H_2O±)	Gas Conditions				Contaminant Loadings				
					Density (#/Ft^3)	Moist. (-Volume % -)	O_2 (-Volume % -)	CO_2 (-Volume % -)	PM (gr/dscf)	SO_2 (-ppm-)	NO_x as NO_2 (-ppm-)		CO (-ppm-)
1. Combustion Air													
a. FD Fan:													
(1) Inlet													
(2) Outlet													
b. Primary Air													
c. Secondary Air													
d. Tertiary													
e. Other (note)													
2. Dutch Oven													
3. Combustion Chamber													
4. Furnace													
5. Passes: a. First													
b. Second													
c. Last													
6. Boiler Outlet													
7. Economizer: a. Flue Gas Inlet													

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

	Temp. (°F)	Velocity (FPM)	Flow Rate (ACFM)	Static Press ("H_2O±)	Gas Conditions				Contaminant Loadings				
					Density (#/Ft^3)	Moist. (-Volume % -)	O_2 (-Volume % -)	CO_2 (-Volume % -)	PM (gr/dscf)	SO_2 (-ppm-)	NO_x (-ppm-)	as NO_2 (-ppm-)	CO (-ppm-)
b. Flue Gas Outlet													
8. Preheater(s): a. Flue Gas Inlet													
b. Flue Gas Outlet													
9. Emission Control Sections: Description a.													
(1) Inlet													
(2) Outlet													
b.													
(1) Inlet													
(2) Outlet													
c.													
(1) Inlet													
(2) Outlet													
10. ID Fan: (1) Inlet													
(2) Outlet													
11. Stack Outlet													

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

V. Order-of-Magnitude Installed Cost Estimates: ($$)

A. Site Preparation _____

B. Foundations and Building(s) _____

C. Basic Boiler (excluding items listing in categories D-G below) _____

D. Boiler-Related _____

1. Fuels and Fuel-Preparation Systems _____
2. Feedwater and Feedwater Preparation Systems _____
3. Draft Equipment, Including Stack _____
4. Instrumentation and Control Systems _____
5. Associated Piping, Electrical, Insulation, etc. _____
6. Other (specify): _____ _____

E. Air Contaminant Control Sections: (specify)

1. _____ _____
2. _____ _____
3. _____ _____
4. _____ _____
5. _____ _____

F. Engineering, Administrative, Supervisory and Start-up Expenses _____

G. Other (specify): _____ _____

PROJECT TOTAL: _____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Southwest Clean Air Agency

Notice of Construction Attachment

INDUSTRIAL FIELD ASSEMBLED BOILER INFORMATION

TransAlta Centralia Generation, LLC
Parent Company Name

TransAlta Centralia Plant
Plant Name

I. General (check appropriate square(s)): **Auxiliary Boiler**

A. Service Conditions: Details:

☐Power Generation
☑Process Steam — Operating as needed to keep Unit #2 building warm during periods of unit shutdown. Also provides process steam to Unit #2 during startup and shutdown of that unit
☐ Waste Heat Recovery
☐ Chemical Recovery
☐ Incineration Features
☐ Space Heat
☐ Other

B. Description:

1. Manufacturer: **TBD**
2. Type and Model No.: **TBD**
3. Fuel Heat Input: **149.13 MMBtu/hr** (Btu/hr)
4. Fuel Heating Value : **1107 Btu/ft³** (Btu/lb or Btu/ft^3)
5. Installation Date: **2027 2028**
6. Dates of Major Rebuilds: N/A
7. Dates of Major Revisions: N/A
8. Drawings:

C. Characteristics:

☐ Fire Tube
☑ Water Tube
☐ Straight Tube
☐ Bent Tube

D. Firing

☐ Dry Bottom
☐ Wet Bottom
☐ Fluidized Bed
☐ Dutch Oven
☐ Direct-Fired Solid Fuel
☑ Single-Fuel Burner(s)
☐ Combination Burner(s)

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

☐ Mechanical Atomization ☐ Steam Atomization
☐ Rotary Cup ☐ Air Atomization
☐ Other_____

Stoker-Fed:

☐ Over-Fed: ☐ Traveling Grate
☐ Shaker Grate
☐ Stationary Grate

☐ Under-Fed
☐ Spreader
☐ Hand

Geometry:

☐ Cyclonic
☐ Tangential
☑ Direct Entry
☐ Other_____

Combustion Air:	Point(s) of Introduction:	Temperatures: Preheated ☐
☐ Primary	_____	_____
☐ Secondary	_____	_____
☐ Tertiary	_____	_____
☐ Other	_____	_____

II. Ratings:

A. Steam Generation (lb/hr):

1. Average Design Load Conditions: 115,000 lb/h___@ 170_____PSIG & 500_____°F

2. Rated Boiler Capacities, Burning: _____(Fuels:)_____

(Natural Gas)(___ _____)(_ _____)(___ _____)

a. Continuous 115,000 lb/h_____

b. Peaking Rate (lb/hr) Time Period

_____ _____
_____ _____

3. Turn-Down: Capable of operating at low turndowns such as 10% however not anticipated to operate at very low loads due to steam demands_____
_____
_____

INTERNAL

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

B. Performance:

1. Inputs-1,000 Btu/hr (HHV):_____(Fuels:)_____

(Natural Gas - 149.13 MMBtu/h)(_____)()(_____)

2. Efficiencies: _____
   a. Over-all, _____
   at conditions: _____

   b. A.S.M.E. Short-form (for units >250 mmBtu/hr input)

	Btu/lb Fuel Fired
(1) Energy absorbed by boiler fluid:	_____
(2) Energy loss due to dry flue gases:	_____
(3) Energy loss due to moisture in fuel:	_____
(4) Energy loss due to evaporating and superheating moisture formed by combustion of hydrogen:	_____
(5) Energy loss due to incomplete combustion of carbon to CO:	_____
(6) Energy loss due to combustible in refuse:	_____
(7) Energy loss due to radiation and unaccounted for:	_____

(Based on_____(Btu/lb) for_____)

3. Applicable NSPS: ***NSPS not applicable (see discussion in Section 3.0 of Application)***

☐ 40 CFR 60.40 (Subpart D) >250 mmBtu/hr constructed/modified after 8/17/71
☐ 40 CFR 60.40a (Subpart Da) >250 mmBtu/hr constructed/modified after 9/18/78
☑ 40 CFR 60.40b (Subpart Db) ≥100 and ≤250 mmBtu/hr constructed/modified after 6/19/84
☐ 40 CFR 60.40c (Subpart Dc) ≥10 and <100 mmBtu/hr constructed/modified after 6/9/89

4. NSPS Emission Limits:

SO_2	NO_x as NO_2	PM	PM_{10}	CO	VOC
_____	0.011 lb/MMBtu	_____	_____	_____	

☑ CEM required, which pollutants: ☐ SO_2 ☑ NO_x ☐ PM ☐ CO
☐ _____
☐ _____

III. Physical Description:

A.	Furnace Parameters (as applicable)	Dutch Oven Parameters (as applicable)
1. Reference Drawings:	_____	_____
2. Dimensions:	_____	_____
3. Grate Area:	_____	_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

4. Water Cooled Surfaces---
Descriptions and square feet:

a. _____ _____
_____ _____

b. _____ _____
_____ _____

c. _____ _____
_____ _____

5. Combustion Air Controls---
Describe _____ _____
_____ _____

6. Burner Specifications:

Type, Make, Model #	Fuel Fired	Rating (Btu/hr)	Number Installed
a. _____	_____	_____	_____
_____	_____	_____	_____
b. _____	_____	_____	_____
_____	_____	_____	_____
c. _____	_____	_____	_____
_____	_____	_____	_____

7. Stoker Specifications (as appropriate):

a. _____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____
b. _____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____

8. Reinjection Details: _____

_____

_____

_____

9. Combustion Control (see also Section III-F):

a. Description: _____

_____

_____

b. Schematic Drawings: _____

_____

_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

10. Ash Removal:

a. Description of Method(s):

(1) _____

_____

(2) _____

_____

B. Evaporative Sections (in addition to area previously noted):

1. Convection Area: Surface Area (ft^2)

a. First Pass _____
b. Second Pass _____
c. Third Pass _____
d. Other (specify as fire tube, etc.)
_____ _____

2. Screen: _____
3. Superheater:

a. Radiant _____
b. Convection _____

4. Reheat _____

5. Economizer _____

6. Other (specify): _____

C. Soot Blowers:

1. Type, Make Model No.	Location	Number

2. Operating Schedule(s):

_____

_____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3. Boiler Conditions While Operating:

D. Steam Drums:

Designation	Inside Dimensions	Number

E. Draft Side Equipment:

1. Air Preheater(s): Type, Make, Model No. Ratings

a.

b.

2. Fans:

	Ratings (max. design) CFM @ S.P. & Gas Conditions	Drive Description (Horse Power)
a. Forced Draft:		
(1) Maximum:		
Design:		
(2) Type, Make, Model:		
b. Induced Draft:		
(1) Maximum:		
Design:		
(2) Type, Make, Model:		
c. Other (specify):		
(1) Maximum:		
Design:		
(2) Type, Make, Model:		

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3. Stack: Height **244 ft** Inside Diameter: **64”**

   a. Configuration: _____ _____

   b. Sampling Ports: Location Number Access Description

   _____ _____ _____
   _____ _____ _____
   _____ _____ _____

   c. Other Units Connected to Stack (list): None

   _____
   _____
   _____

   d. Bypass Capability - explain: None

   _____
   _____
   _____

F. Instrumentation and Control:

	Gage or Meter	Controller/ Recorder	Manual	Auto	Schematic Reference
1. Feed Water:					
2. Draft: (note)					
3. Fuel: (note)					
4. Steam Flow:					

5. Flue Gas, Temperature, Emission Control, etc.: (note), ***see Appendix E for modeling parameters***

a.			
b.			
c.			
d.			
e.			
f.			
g.			
h.			

IV. Operating Parameters:

A. Fuels Burned (list): **Natural gas**

1. Maximum Rate: _____
(149.13 MMBtu/h)(_____)(_____)(_____)
2. Higher Heating Value (BTU/same units as above): 1107 Btu/scf

3. Proximate Anal. (as received): Average Maximum

a. Moisture _____ _____
b. Ash _____ _____

4. Ultimate Analysis: (wt.%, dry basis)
a. Sulfur _____ _____
b. Hydrogen _____ _____
c. Carbon _____ _____
d. Nitrogen _____ _____
e. Oxygen _____ _____

B. Operating Schedule:

1. Anticipated % of Annual Through-Put (by quarter):

Fuel:				
Period:				
Dec-Feb				
Mar-May				
Jun-Aug				
Sep-Nov				

2. Normal Schedule:

Period:	Hrs/Day	Days/Wk	Wks/Period
Dec-Feb			
Mar-May			
Jun-Aug			
Sep-Nov			

3. Scheduled Shut-Downs:

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

C. Gas Profiles (Please complete where data is readily obtainable or reasonably estimated. Underline all estimated values. Note that the profile desired is for maximum average firing conditions with the most likely fuel inputs.): ***See emissions inventory information in Appendix B.***

Firing conditions for following profile:_____

	Temp. (°F)	Velocity (FPM)	Flow Rate (ACFM)	Static Press ("H_2O±)	Gas Conditions				Contaminant Loadings				
					Density (#/Ft^3)	Moist. (-Volume % -)	O_2 (-Volume % -)	CO_2 (-Volume % -)	PM (gr/dscf)	SO_2 (-ppm-)	NO_x as NO_2 (-ppm-)		CO (-ppm-)
1. Combustion Air													
a. FD Fan:													
(1) Inlet													
(2) Outlet													
b. Primary Air													
c. Secondary Air													
d. Tertiary													
e. Other (note)													
2. Dutch Oven													
3. Combustion Chamber													
4. Furnace													
5. Passes: a. First													
b. Second													
c. Last													
6. Boiler Outlet													
7. Economizer: a. Flue Gas Inlet													

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

	Temp. (°F)	Velocity (FPM)	Flow Rate (ACFM)	Static Press ("H_2O±)	Gas Conditions				Contaminant Loadings				
					Density (#/Ft^3)	Moist. (-Volume % -)	O_2 (-Volume % -)	CO_2 (-Volume % -)	PM (gr/dscf)	SO_2 (-ppm-)	NO_x as NO_2 (-ppm-)		CO (-ppm-)
b. Flue Gas Outlet													
8. Preheater(s): a. Flue Gas Inlet													
b. Flue Gas Outlet													
9. Emission Control Sections: Description a.													
(1) Inlet													
(2) Outlet													
b.													
(1) Inlet													
(2) Outlet													
c.													
(1) Inlet													
(2) Outlet													
10. ID Fan: (1) Inlet													
(2) Outlet													
11. Stack Outlet													

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

V. Order-of-Magnitude Installed Cost Estimates: ($$)

A. Site Preparation _____

B. Foundations and Building(s) _____

C. Basic Boiler (excluding items listing in categories D-G below) _____

D. Boiler-Related _____

1. Fuels and Fuel-Preparation Systems _____
2. Feedwater and Feedwater Preparation Systems _____
3. Draft Equipment, Including Stack _____
4. Instrumentation and Control Systems _____
5. Associated Piping, Electrical, Insulation, etc. _____
6. Other (specify): _____ _____

E. Air Contaminant Control Sections: (specify)

1. _____ _____
2. _____ _____
3. _____ _____
4. _____ _____
5. _____ _____

F. Engineering, Administrative, Supervisory and Start-up Expenses _____

G. Other (specify): _____ _____

PROJECT TOTAL: _____

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Southwest Clean Air Agency

FURNACES, OVENS AND SMALL BOILERS AIR DISCHARGE PERMIT APPLICATION DATA SHEET	Page 1 of 5 Application No:_____

Please provide the following information concerning the proposed equipment. SWCAA may require additional information after review of the submitted application. Please attach any information that might aid in SWCAA's review of the Air Discharge Permit Application Data Sheet. In addition to this application form, all sources are required to demonstrate that proposed equipment meets the requirements of Best Available Control Technology (BACT).

APPLICANT INFORMATION:

Applicant Name: TransAlta Centralia Generation, LLC

Mailing Address: 913 Big Hanaford Road, Centralia, WA 98531
Street City State Zip

Facility Identification: Airs # 53-041-10010

Facility Address: 913 Big Hanaford Road, Centralia, WA 98531
Street City State Zip

Contact Name / Title: Conrad Wieclaw, Engineering & Environmental Manager

EQUIPMENT DATA: (Check all that apply) *This form covers both Water Bath Heaters, as they are identical*

Type:
- ☐ Boiler
- ☐ Furnace
- ☐ Oven
- ☐ Reactor/Oxidizer
- ☑ Other Water bath heater

Use:
- ☐ Power Generation
- ☐ Steam Generation
- ☐ Reactor/Reformer/Oxidizer
- ☐ Drying-Baking Oven
- ☑ Other Indirectly heating natural gas to prevent condensation

Boiler:
Manufacturer: TBD
Model No: _____
Serial No: _____

Burner:
Manufacturer: TBD
Model No: _____
Serial No: _____

Date Produced: TBD
Date Reconstructed (if applicable): N/A
Boiler Configuration (fire tube, water tube, fluidized bed, etc.): _____

Primary fuel
Type: Natural gas
Burner Manufacturer: TBD
Burner Model No.: _____
Rated Heat Input Capacity: 10 MMBtu/hr
Fuel Consumption Rate: 9033 ☐ gal/hr ☑ ft^3/min

Secondary fuel
Type: None
Burner Manufacturer: N/A
Burner Model No.: _____
Rated Heat Input Capacity: _____ MMBtu/hr
Fuel Consumption Rate: _____ ☐ gal/hr ☐ ft^3/min

Exhaust Flowrate: 6500 ☑ acfm ☐ dscfm
Turn-down Ratio: TBD
Bypass Capability: N/A

Stack Height: Above ground level: 25 ☑ feet ☐ meters Above Roof Level: TBD ☑ feet ☐ meters
Stack Diameter: 2 ☐ inches ☑ feet
Stack Discharge Temperature: 700 °F **Only use approved rain caps that do not interfere with vertical discharge.**

Distance to:
Property Boundary: 80 ☑ feet ☐ meters
Nearest Building: 80 (from tank) ☑ feet ☐ meters
Closest Residential Dwelling: 1 mile ☐ feet ☐ meters
Building Dimensions: TBD

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Southwest Clean Air Agency

FURNACES, OVENS AND SMALL BOILERS	Page 2 of 5
AIR DISCHARGE PERMIT APPLICATION DATA SHEET	Application No:_____

OPERATIONAL DATA:

Use: ☐ Power Generation ☐ Reactor/Reformer/Oxidizer ☑ Other Water bath heater
☐ Steam Generation ☐ Drying-Baking Oven

Maximum Load Condition: 10 MMBtu/hr Average Load Condition: TBD MMBtu/hr
Steam generation: N/A lb/hr _____ PSIG & _____ °F

Process Equipment Served by Boiler:
The water bath heaters indirectly heat incoming natural gas to keep the temperature above the point where water or hydrocarbon hydrates could condense in the gas, particularly as pressure drops to meet Unit #2 and auxiliary boiler fuel input requirements.

Hours of Operation: Maximum: 24 hr/day, 7 days/wk, 52 weeks/yr
Average: T B D hr/day, _____ days/wk, _____ weeks/yr

OVEN/REACTOR/REFORMER DATA:

Process Description: N/A

Feed Stock: _____ Rate of Feed: _____
Inlet Temperature: _____ ☐ °F ☐ °C Outlet Temperature: _____ ☐ °F ☐ °C
Dimensions: H _____ W _____ D _____ Diameter _____ Length _____ ☐ feet ☐ inches
Capacity: _____ ☐ gal ☐ ft^3 Construction Material: _____

EMISSION CONTROL EQUIPMENT DATA:

Equipment Description	Controlled Pollutant	Performance Guarantee
Low NOx burners	NOx	9 ppm
	CO	50 ppm

EMISSION FACTORS/DATA: *See Appendix B of the application for all emissions data*

Pollutant	Emission Factor	Emission Factor Units	Emission Factor Source
Nitrogen Oxides (NO_x)			
Carbon Monoxide (CO)			
Volatile Organic Compounds (VOC)			
Particulate Matter (PM)			
Sulfur Dioxide (SO_2)			
Oxygen (O_2)			
Carbon Dioxide (CO_2)			

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

FURNACES, OVENS AND SMALL BOILERS
AIR DISCHARGE PERMIT APPLICATION DATA SHEET

Application No:_____

Use of this form will assist in receiving approval for equipment or processes used to control emissions of volatile organic compounds (VOC). The information requested on the reverse side of this form is necessary for SWCAA to evaluate whether your proposal can comply with federal, state, and local requirements. It does not necessarily mean the Notice of Construction (NOC) will be approved as submitted. Your NOC will be approved or denied only after submittal and evaluation of all required information. However, the time required to evaluate your application will be significantly shortened if the information you submit is complete.

General Information to be Submitted As Applicable

1. The maximum and average VOC in parts per million, by volume, as methane, in the exhaust stream, before and after control.
2. The concentration of toxics as identified in WAC 173-460, "Controls for New Sources of Toxic Air Pollutants" from VOCs identified in item 1 above must be listed.
3. The maximum and average flow rates of the contaminated gas streams in standard cubic feet per minute. Provide the basis and source of this information.
4. Calculations to show how the blower was sized to deliver the amount of flow in item 3 above.
5. A process and instrumentation diagram showing the type and locations of the meters, gauges, feedback controllers, regulators and recorders, etc...
6. A plot plan showing the location and neighborhood of the proposed project including distance to adjacent property lines and elevation of discharge stack.
7. The discharge stack shall not have a rain cap or cover that inhibits vertical discharge from the stack.
8. A copy of the Operations and Maintenance (O&M) Manual for all control equipment.
9. The method of indicating and recording hours of operation.
10. The horsepower of the blower, type of fuel, maximum Btu/hour rating and minimum temperature at which the gas flow will be maintained during oxidation.
11. The instrumentation to maintain and control the temperature in the oxidizer.
12. The preheat temperature of the gas stream before entering the catalyst.
13. The temperature increase across the catalyst bed as a function of inlet VOC concentrations.
14. The efficiency of the catalyst based on manufacturer's specifications.
15. A description on how the generator/compressor operates i.e., constant RPM, how the fuel to the engine will be regulated as the hydrocarbon concentration in the inlet gas decreases.
16. A description of the how the catalyst system functions and specifically which engine operating parameters can affect its performance.
17. Engineering calculations based on which the system in a) was chosen and how adequate the catalyst beds are for venting the engine exhaust.
18. The calculations in e) must include the maximum flowrate of gas through the engine, chemical compositions (NOx, CO, O2, CO2, and non-methane hydrocarbons) in the exhaust gas from the engine, and from each stage of the catalyst.

FUEL DATA:

Use No. 2 Diesel Fuel, if equipment is diesel fueled. Sulfur Content: 0.0015 percent (15 ppm) maximum allowed for diesel.
Density : 7.206 lb/gal (#2 diesel) 8.212 lb/gal (#6 fuel oil) 0.04491 lb/ft^3 (natural gas)
Heating Values: #2 diesel = 19,404 Btu/lb (141,000 Btu/gal) #6 oil = 18,245 Btu/lb (150,000 Btu/gal) natural gas = 22,410 Btu/lb (1006 Btu/ft^3)

EMISSION FACTORS: (for information and reference only)

#2 Diesel Fuel: from Air Pollution Engineering Manual Fuel Oil Combustion Table 2 Page 248 (uncontrolled factors)

(k = thousand) heat input	Utility\large industrial unit (>100 million Btu/hr)	Small industrial unit (10 to 100 million Btu/hr)	Commercial unit (0.3 to <10 million Btu/hr)	Residential unit (<0.3 million Btu/hr)
Oxides of Nitrogen (NOx)	: NA lb/k gal	: 20.0 lb/k gal	: 20.0 lb/k gal	: 18.0 lb/k gal
Carbon Monoxide (CO)	: NA lb/k gal	: 5.0 lb/k gal	: 5.0 lb/k gal	: 5.0 lb/k gal
Volatile Organic Compounds (VOC)	: NA lb/k gal	: 0.2 lb/k gal	: 0.34 lb/k gal	: 0.713 lb/k gal
Filterable Particulate Matter [1]	: NA lb/k gal	: 2.0 lb/k gal	: 2.0 lb/k gal	: 2.5 lb/k gal
Condensable Particulate Matter [2]	: NA lb/k gal	: NA lb/k gal	: NA lb/k gal	: NA lb/k gal
Sulfur Dioxide (SO_2)	: NA lb/k gal	: 142S [3] lb/k gal	: 142S lb/k gal	: 142S lb/k gal

Note: VOCs are nonmethane component

#6 Fuel Oil: from AP-42, Tables 1.3-2,3,4 (uncontrolled factors)

(k = thousand) heat input	Utility\large industrial unit (>100 million Btu/hr)	Small industrial unit (10 to 100 million Btu/hr)	Commercial unit (0.3 to <10 million Btu/hr)	Residential unit (<0.3 million Btu/hr)
Oxides of Nitrogen (NOx)	: 67.0 lb/k gal	: 55.0 lb/k gal	: 55.0 lb/k gal	: 18.0 lb/k gal
Carbon Monoxide (CO)	: 5.0 lb/k gal	: 5.0 lb/k gal	: 5.0 lb/k gal	: 5.0 lb/k gal
Total Organic Compounds (TOC)	1.04 lb/k gal	: 1.605 lb/k gal	: 0.475 lb/k gal	: 2.493 lb/k gal
Filterable Particulate Matter [1]	: (9.19 + 3.22) lb/k gal	: (9.19S + 3.22) lb/k gal	: (9.19S + 3.22) lb/k gal	: 0.3 lb/k gal
Condensible Particulate Matter [2]	NA	: 7.5 lb/k gal	: 7.5 lb/k gal	: 11.0 lb/k gal
Sulfur Dioxide (SO_2)	: 157S lb/k gal	: 157S lb/k gal	: 157S lb/k gal	: 142S lb/k gal

Natural Gas: from AP-42, Tables 1.4-1,2,3 (uncontrolled factors)

(M = million) heat input	Utility\large industrial unit (>100 million Btu/hr)	Small industrial unit (10 to 100 million Btu/hr)	Commercial unit (0.3 to <10 million Btu/hr)	Residential unit (<0.3 million Btu/hr)
Oxides of Nitrogen (NOx)	: 550.0 lb/M ft^3	: 140.0 lb/M ft^3	: 100.0 lb/M ft^3	: 94.0 lb/M ft^3
Carbon Monoxide (CO)	: 40.0 lb/M ft^3	: 35.0 lb/M ft^3	: 21.0 lb/M ft^3	: 40.0 lb/M ft^3
Total Organic Compounds (TOC):	1.7 lb/M ft^3	: 5.8 lb/M ft^3	: 8.0 lb/M ft^3	: 11.0 lb/M ft^3
Filterable Particulate Matter [1]	: 5.0 lb/M ft^3	: 6.2 lb/M ft^3	: 4.5 lb/M ft^3	: 0.18 lb/M ft^3
Condensible Particulate Matter [2]	NA lb/M ft^3	: 7.5 lb/M ft^3	: 7.5 lb/M ft^3	: 11.0 lb/M ft^3
Sulfur Dioxide (SO_2)	: 0.6 lb/M ft^3	: 0.6 lb/M ft^3	: 0.6 lb/M ft^3	: 0.6 lb/M ft^3

1. Filterable particulate matter (PM) is that particulate matter collected on or prior to the filter of an EPA Method 5 sampling train.
2. Condensable particulate matter (PM) is that particulate matter collected in the impinger portion of an EPA Method 5 sampling train.
3. S indicates that the weight percent of sulfur in the oil should be multiplied by the value given.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Southwest Clean Air Agency

FURNACES, OVENS AND SMALL BOILERS AIR DISCHARGE PERMIT APPLICATION DATA SHEET	 Application No:_____

EMISSIONS CALCULATIONS

Emissions = Emission Factor X Fuel Consumption Rate X Specific Weight of Fuel X Fuel Heating Value X Usage Time X Ton Conversion

E = (lb/1,000 gal) X (gal/hr) X (hr/year) X (ton/2000 lb)

Example: E_{NOX} for diesel = (20.0 lb/1,000 gal) X (25.0 gal/hr) X (24 hr/day) X (7 days/wk) X (52 wk/yr) X (1 ton/2000 lb)

= 2.18 tons/yr

Note - If using other than No. 2 diesel for diesel applications, the emission factor may vary; see AP-42 for emission factors for other fuel types.

Calculate emissions for each criteria pollutant below as it applies to the proposed installation and summarize below.

E_{NOX} = _____ = _____ tons/yr

E_{CO} = _____ = _____ tons/yr

E_{VOC} = _____ = _____ tons/yr

E_{SOX} = _____ = _____ tons/yr

E_{PM} = _____ = _____ tons/yr

= = = = = = = = = = =

E_{TOTAL} = (E_{NOX} + E_{CO} + E_{VOC} + E_{SOX} + E_{PM}) **REGULATED EMISSIONS TOTAL = _____ tons/yr**

Additional emission considerations:

E_{PM10} = .96 (PM) = _____ tons/yr

E_{CO2} = _____ = _____ tons/yr

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Southwest Clean Air Agency

FURNACES, OVENS AND SMALL BOILERS AIR DISCHARGE PERMIT APPLICATION DATA SHEET	Page 5 of 5 Application No:_____

EXHAUST GAS FLOWRATE CALCULATION
(Conversion from acfm to dscfm)

The following equation converts a flowrate for a given condition noted as actual cubic feet per minute (acfm) to a flowrate in cubic feet per minute at dry standard temperature and pressure conditions (dscfm). The applicant should provide the actual flowrate in acfm, pressure in inches of mercury, moisture in percentage, and temperature in degrees Rankine to the following equation to make the conversion.

$$F_{dscfm} = F_{acfm} \times \frac{T_{dscfm} \times P_{acfm}}{T_{acfm} \times P_{dscfm}} \times \frac{1 - M}{100}$$

where:

F_{dscfm} = Exhaust flowrate at standard temperature and pressure in dry standard cubic feet per minute
F_{acfm} = Exhaust flowrate at measured temperature and pressure in actual cubic feet per minute
T_{dscfm} = Temperature at standard conditions in degrees Rankine (460 + 68 °F)
T_{acfm} = Temperature of actual exhaust discharge in degrees Rankine (460 + T °F)
P_{dscfm} = Pressure at standard conditions in inches of mercury (29.92 in Hg)
P_{acfm} = Pressure of actual exhaust discharge in inches of mercury (P_{acfm} in Hg)
M = Exhaust gas percent moisture as measured (decimal equivalent)

$$F_{dscfm} = ____ \times \frac{530 \times ____}{____ \times 29.92} \times \frac{1 - ____}{100}$$

Flowrate = _____ dscfm

EXHAUST GAS PARTICULATE CONCENTRATION (PC)

The following equation is used to calculate the particulate concentration (PC) in the exhaust gas stream. The applicant should provide the missing data for maximum pounds of particulate per hour in the exhaust gas stream and the flowrate of the exhaust stream in cubic feet per minute.

$$PC = \frac{R_1 \ lbPM/hr\,(\max) \times 7000 \ grains/lb}{F_1 \ ft^3 \times 60 \ \min/hr}$$

where:

PC = particulate concentration (grains/dscf)
R_1 = particulate mass emission rate (lb/hr)
F_1 = flowrate in dry standard cubic feet per minute (dscfm)

$$PC = \frac{____ \ lb PM/hr\,(\max) \times 7000 \ grains/lb}{____ \ ft^3 \times 60 \ \min/hr}$$

Particulate Concentration = _____ grains/dscf

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/31/2021

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ **new** ☑ **revised** ☐ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Centralia Plant	WA	03845

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
BW22	Yes
(converting from coal to natural gas)	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Centralia Plant
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
   (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
   (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
   (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
   (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
   (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
   (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
   (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
   (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Centralia Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Centralia Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Conrad Wieclaw	
Signature Signed by: Conrad Wieclaw 130F85AFA0D74B4...	Date 13 January 2026 | 9:05 AM MST

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the Title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the Title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the Title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy's (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the Title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a Title V permit, or such longer time as provided for under the Title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate Title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Clean Air Markets Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX B: EMISSIONS CALCULATIONS

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
					(tons per year)					
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.000	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

[2]Baseline emissions compiled from emission inventories submitted to and approved by Southwest Clean Air Agency for the respective reporting years with the exception of CO_{2e}. CO_{2e} emissions were compiled from 40 CFR 98, Greenhouse Gas Reporting summaries.

[3]Pursuant to 40 CFR 52.21(b)(i), "For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project." TransAlta chose the 2022-2023 period for Unit 2.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NOx^{1}	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.009**	**2,291,727**

*The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Unit 2 Full load, 59% capacity operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	7,500.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	59%	
Hours of Operation =	5,168	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	5,168	hr/yr
NG Fuel Usage =	35,016.26	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	8.25E+02	2,131.97
CO	0.15	lb/MMBtu	TA Predicted	1.13E+03	2,907.23
VOC	0.003	lb/MMBtu	TA Predicted	2.25E+01	58.14
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	5.39E+00	13.92
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	8.24E-02	0.21
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	8.77E+05	2,267,195
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+01	42.73
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+00	4.27
CO_{2e}	-			8.78E+05	2,269,524
HAPs	See table below				33.06

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (7500 MMBtu/hr) = 51.4905 lbs/hr
PM Emissions (tons/yr) = (51.4905 lbs/hr) x (5168.4 hrs/yr) / (2000 lbs/ton) = 133.062 tons/yr

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	4.2E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	2.8E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	4.2E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	3.7E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	2.1E-02
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	5.3E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	4.9E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	1.3E+00
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	3.2E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	1.1E-02
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	3.0E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	8.8E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	6.0E-02
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	3.5E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	2.1E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.9E-02
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	2.0E-02
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	4.4E-03
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	1.5E-03
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	1.5E-02
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	8.8E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	6.7E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	4.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	3.7E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	4.2E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	4.0E-02
				NG HAPs Total	**33.06**

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9
https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response
https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf
https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Unit 2 190 MW operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	2,529.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	100%	
Hours of Operation =	8,760	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	8,760	hr/yr
NG Fuel Usage =	20,012.68	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	2.78E+02	1,218.47
CO	0.15	lb/MMBtu	Proposed BACT	3.79E+02	1,661.55
VOC	0.003	lb/MMBtu	TA Predicted	7.59E+00	33.23
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	1.82E+00	7.96
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	2.78E-02	0.12
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	2.96E+05	1,295,760
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E+00	24.42
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E-01	2.44
CO_{2e}	-			2.96E+05	1,297,091
HAPs	See table below				18.90

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (2529 MMBtu/hr) = 17.3626 lbs/hr
PM Emissions (tons/yr) = (17.3626 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 76.048 tons/yr

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP		--	
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.4E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.6E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.4E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	2.1E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.2E-02
Ethylbenzene	100-41-4	HAP		--	
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	3.0E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.8E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	7.5E-01
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.8E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	6.1E-03
OCDD	3268-87-9	HAP		--	
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.7E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	5.0E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.4E-02
o-Xylene	95-47-6	HAP		--	
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	2.0E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.2E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.1E-02
Chromium III	7440-47-3	HAP	1.4E-03	AP-42, Table 1.4-4 [1]	1.4E-02
Chromium VI	18540-29-9	HAP	0.0E+00	AP-42, Table 1.4-4 [1]	0.0E+00
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	8.4E-04
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	8.5E-03
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	5.0E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.8E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	2.1E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.4E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.3E-02
				NG HAPs Total	**18.90**

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9

https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response

https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Natural gas venting re: shutdown

Natural gas vented per shutdown:	20,000	scf/shutdown
NG % methane (CH_4) composition:	95%	
CH_4 vented per shutdown:	19,000	scf/shutdown
Number of shutdowns per year:	50	shutdowns/yr
CH_4 vented per year:	950,000	scf/yr
Conversion	2,000	lb/ton
CH_4 density at STP:	0.04475	lb/scf
CH_4 Global Warming Potential [1]	28	
Mass of CH_4 vented per year:	42,513	lb/yr
Mass of CH_4 vented per year:	21	tons/yr
CO_{2e} vented per year:	595	tons/yr

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Auxiliary Boiler

Max. Fuel Combustion Rate =	149.13 MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	175.13 MMscf/yr	CO_2	1
Hours of Operation =	1,300 hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107 MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650 gr/MMscf		
Conversions:	2.2046 lb/kg		
	2,000 lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.02E+00	0.67
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	2.24E+00	1.45
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	5.52E+00	3.59
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	7.41E-01	0.48
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	1.07E-01	0.07
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.64E-03	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.74E+04	11,339
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-01	0.21
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-02	0.02
CO_{2e}	-			1.75E+04	11,351
HAPs	See table below				0.17

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2024

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (149.13 MMBtu/hr) = 1.0238 lbs/hr
PM Emissions (tons/yr) = (1.0238 lbs/hr) x (1300 hrs/yr) / (2000 lbs/ton) = 0.665 tons/yr

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Aux Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.1E-06
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.4E-06
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.1E-07
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	1.8E-04
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.1E-04
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	2.6E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.5E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	6.6E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.6E-01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	5.3E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.5E-06
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	4.4E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.0E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	1.8E-05
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.1E-06
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	9.6E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	1.0E-04
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	2.2E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	7.4E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	7.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	4.4E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.3E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.3E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	1.8E-04
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.1E-06
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.0E-04
				NG HAPs Total	**0.17**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Water Bath Heater 1

Max. Fuel Combustion Rate =	10.00	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	79.13	MMscf/yr	CO_2	1
Hours of Operation =	8,760	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.
[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 1 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Water Bath Heater 2

Max. Fuel Combustion Rate =	10.00	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	79.13	MMscf/yr	CO_2	1
Hours of Operation =	8,760	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1.

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 2 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Cooling Tower 1 - Serving Unit 2

Water flow:	120,000	gpm
Hours of Operation:	8760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \qquad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)

TDS = Concentration of total dissolved solids in circulating water (PPM by weight)

η_{Drift} = Drift loss of circulating water (%)

ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal	
PM =	0.76	tons/yr	1.51
PM_{10} =	0.76	tons/yr	1.51
$PM_{2.5}$ [3]=	0.45	tons/yr	

[1] Current BACT requirement for DOE and SWCAA.

[2] South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, December 2022

[3] PM2.5 fraction = 0.6*PM10 fraction, Maricopa County Air Quality, Reporting Emissions From Cooling Towers, January 2025

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Cooling Towers

*Transalta Unit #2 cooling tower testing (12/3/24-01/02/25) - only listed constituent is silica

Total TDS**	576 ppm		
Silica CAS No. 7631-86-9 (TAPs only)	144 ppm	Ratio of silica to TDS	25%
Silica emissions			0.19 tons/yr

**Assume that PM emissions are representative of TDS, therefore 25% of PM emissions are silica

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Cooling Tower 2- Serving Unit 2

Water flow:	120,000	gpm
Total Possible Hours (hrs/yr):	8,760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \qquad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)

TDS = Concentration of total dissolved solids in circulating water (PPM by weight)

η_{Drift} = Drift loss of circulating water (%)

ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal
PM =	0.76	tons/yr
PM10 =	0.76	tons/yr
PM2.5=	0.45	tons/yr

[1] Current BACT requirement for DOE and SWCAA.
[2] South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, December 2022
[3] PM2.5 fraction = 0.6*PM10 fraction, Maricopa County Air Quality, Reporting Emissions From Cooling Towers, January 2025

*Transalta Unit #2 cooling tower testing (12/3/24-01/02/25) - only listed constituent is silica

Total TDS**	576 ppm		
Silica CAS No. 7631-86-9 (TAPs only)	144 ppm	Ratio of silica to TDS	25%
Silica emissions			0.19 tons/yr

**Assume that PM emissions are representative of TDS, therefore 25% of PM emissions are silica

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX C: SUPPORTING DOCUMENTATION FOR REGULATORY ANALYSIS

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

TETRA TECH

Technical Memo

To:	Scott Jeffers and Vincent Light, TransAlta
From:	Debbie Skibicki, PE
Date:	April 22, 2025
Subject:	PSD Analysis for TransAlta Centralia Generating Station Coal-to-Gas Conversion, Reactivation Policy

In discussions with the Washington Department of Ecology (DOE) on April 9, 2025, on the TransAlta Coal-to-Gas (CTG) conversion at the Centralia Generating Station, DOE brought up their interpretation of reactivation policy with respect to that project. DOE specifically mentioned the November 1, 2017 "Guidance on Washington's Prevention of Significant Deterioration [PSD] Permitting Program" (DOE Guidance, Publication no. 17-02-014), Section 2.2.2.1.3 – Restarting Emissions Units. DOE's Guidance document states that "when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways." Section 2.2.2.1.3 of that guidance focuses on reactivation, described as a "permanently" shutdown plant being restarted as a new source. This discussion elaborates on both DOE and EPA guidance and associated site-specific criteria for the TransAlta Centralia site and the CTG project.

1.0 DOE REACTIVATION POLICY

Section 2.2.2.1.3 of the DOE Guidance, under "Reactivation Policy," states the following:

> "*EPA's policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.*[1] *Reactivating a "permanently" shut down source makes the source a new source under current PSD guidance. A source shutting down for more than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

DOE further states:

> *Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

[1] DOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[2] with that intention being the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in their discussions with Lewis County; the regional air permitting authority, Southwest Clean Air Agency (SWCAA), and DOE in addition to vendors, customers, interested stakeholders, etc. has specifically defined their intent to continue operation of the Centralia Plant as a CTG generation resource. These plans were developed prior to the impending ceasing of coal combustion and will continue to build in depth and intensity through the startup of the CTG operations.

DOE refers to the following factors to determine the intent of the owner or operator (the factors will be discussed individually).

1. **The amount of time the facility was out of operation.**

The drivers behind Unit 2 being out of operation are the regulatory process and the construction required for the CTG conversion and life extension of Unit 2. With a smooth regulatory process (started prior to the shutdown, as evidenced in our meetings with DOE), the construction processes could be accomplished with a shutdown of approximately 2 years.

2. **The reason for the shutdown.**

In the 2017 First Amendment to the 2011 Memorandum of Agreement (MOA) between TransAlta and State of Washington, TransAlta agreed to "permanently cease coal-fired power generation" of Unit 2 at the end of 2025. That 2017 Amendment also clarified the anticipated future use of the plant on fuel other than coal. DOE acknowledged TransAlta's consideration of a CTG conversion of Unit 2 in its 2020 Second Revision to its Best Available Retrofit Technology (BART) Order No. 6426 and related Technical Support document for Second BART Order Revision.

3. **Statements by the owner and operator regarding intent.**

As described above, in 2017, TransAlta was actively exploring the possibility of converting the boilers (one or both units) to operate on natural gas instead of coal. To clarify the MOA parties' mutual intent that the plant might continue to generate electricity as long as coal was not the fuel, the parties modified MOA Recital D(5) to clarify that TransAlta would: "permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA." Similarly, Section 6 of the 2017 Amendment revised MOA Section 7, Sentence 2 to read: "Further the State agrees to recognize the Company's cessation of coal fired generation at the

[2] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Facility's boilers prior to the end of their useful lives by taking the early cessation into consideration during future environmental regulatory processes that may adversely affect the Facility's operations."

As recently as this week, TransAlta has been open with Lewis County, SWCAA, DOE and others regarding its intent for fuel conversion at Unit 2 for continued power generation purposes.

4. **The cost and time required to reactivate the facility.**

EPA's reactivation guidance largely applies to facilities shutting down/being mothballed and subsequently being restarted. The DOE referenced guidance (and that mentioned here) does not include conversion to another fuel type, as is discussed in this instance. The costs to reactivate after being mothballed (deactivated for extended period) are approximately $1.5 million including efforts to dehumidify/dry out the boiler and turbine, maintain the units with respect to moisture and corrosion, and then prepare the unit to run again.

For this project, TransAlta is proposing fuel conversion of Unit 2 in addition to life extension, for which the total cost would approximately 1/3 or less of the cost of new build natural gas fired combined cycle turbine unit (including contingency and engineering, procurement, and construction premium). The life extension costs would be incurred to allow the facility to run for another 17 years and are not directly related to the fuel conversion. Those costs would include replacing the cooling towers, feedwater heaters, etc. As discussed above, the total effort could be accomplished in approximately 2 years.

5. **Status of the facility's permits.**

TransAlta will be applying for the appropriate construction permits for their proposed action, as current agency discussions indicate. Other permits (including the Title V Operating Permit #SW98-8-R5 and Acid Rain permit) will remain in force. TransAlta will apply for a Title V modification to update the permit to reflect current operations per the Title V modification requirements in WAC 173-401-725 and would provide an updated compliance plan under the Acid Rain rules. In addition, TransAlta will continue to maintain emissions inventory reporting as required by SWCAA rules 400-105(1).

6. **The record of ongoing maintenance and inspections that were conducted during the shutdown.**

TransAlta will be performing ongoing maintenance and inspections while construction on Unit 2 is taking place for the fuel conversion. The maintenance and inspections would occur on the facility as a whole, in maintaining existing, unchanged units; in the construction of new units; and in the removal of no longer needed components. TransAlta can provide those records during the conversion/construction/shutdown period upon request.

7. **Whether the shutdown was considered as a decrease in a "netting" calculation.**

The temporary shutdown of Unit 2 has not been considered as a decrease in a "netting calculation." The previous 2-year average emissions baseline is being used to determine if a major modification has been triggered for Unit 2 in the CTG conversion. However, no netting occurred or is proposed in the regulatory applicability process.

8. **Whether the allowable emissions level after restarting the facility are higher than as of the date of the shutdown.**

The allowable emissions level of Unit 2 following the CTG conversion will be less than the previous coal 2-year average baseline for all PSD pollutants with the possible exception of volatile organic compounds (VOC). Coal combustion creates negligible VOC emissions, so the previous baseline level was essentially zero.

In addition to the criteria above and TransAlta's clear intent to continue operation of the Centralia Plant as a CTG generation resource, DOE also was aware of the plans and indicated as such in its July 2020 Second Revision to its Best Available Retrofit Technology (BART) Order (Order No. 6426) and related Technical Support Document. The Technical Support document states on Page 1, "Ecology is also modifying the compliance schedule to eliminate

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

the requirement to demolish the coal units to align the BART order's language with language in the MOA between the State of Washington and TransAlta."

DOE's Technical Support Document also quotes the 2017 MOA and notes that SWCAA would have authority over air permitting for conversion: "If TransAlta decides to ***switch to non-coal power generation***, a Notice of Construction application would need to be submitted ***to Southwest Clean Air Agency*** by the company." This language implies that the question of reactivation was not at issue in those discussions.

2.0 CONCLUSION

As mentioned in the DOE PSD Guidance document as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear – the Unit 2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of that goal. That driver and the other criteria support the conclusion that the limited shutdown of Unit 2 was "not intended to be permanent." Thus, Unit 2 should not be viewed as a new source under these circumstances.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX D: SUPPORTING DOCUMENTATION FOR BACT AND TBACT ANALYSES

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS

LARGE NATURAL GAS FIRED BOILERS (Process code 11.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - PM	EMISSION LIMIT - PM
LA-0406	MCA GEIMAR SITE	LA	7/24/2024	CO MeOH Auxiliary Boiler (EQT0001)	321 MMBtu/hr	Natural gas use, good combustion practices, prope	0.0075 lb/MMBtu
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	TX	2/5/2024	Auxiliary Boiler	>250 MMBtu/hr	Good combustion practices	0.0075 lb/MMBtu
LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR • Auxiliary Boiler	1100 MMBtu/hr	Good combustion practices	0.0075 lb/MMBtu
LA-0394	SHELL CHEMICAL GEISMAR PLANT	LA	12/12/2023	01-22 • A0-5 Boiler	350 MMBtu/hr	Proper burner design and fuel specifications	0.0084 lb/MMBtu
TX-0936	VALERO BILL GREEHEY REFINERY	TX	3/29/2022	Boiler	334 MMBtu/hr	None listed	
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Pipeline quality natural gas and good combustion practices	0.0058 lb/MMBtu
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 MMBtu/hr	None listed	
	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 MMBtu/hr	None listed	
MI-0440	MICHIGAN STATE UNIVERSITY*	MI	5/22/2019	EUSTMBoiler	300 MMBtu/hr	Good combustion practices	0.0077 lb/MMBtu (natural gas) 0.024 lb/MMBtu (fuel oil)
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Auxiliary Boller	773 MMBtu/hr	Good combustion practices	
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 • Boiler 1 (EQT0003)	350 MMBtu/hr	Pipeline quality natural gas and good combustion practices	0.0058 lb/MMBtu
	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 • Boiler 2 (EQT0004)	350 MMBtu/hr	Pipeline quality natural gas and good combustion practices	0.0058 lb/MMBtu

Original construction dates 1970, modified in 2019

* Uses No 2 fuel oil as backup

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS
LARGE NATURAL GAS FIRED BOILERS (Process code 11.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - NOx	EMISSION LIMIT - NOx
LA-0406	MCA GEIMAR SITE	LA	7/24/2024	CO MeOH Auxiliary Boiler (EQT0001)	321 MMBtu/hr	SCR & LNB	0.015 lb/MMBtu, rolling 30-day avg
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	TX	2/5/2024	Auxiliary Boiler	>250 MMBtu/hr	Low NOx Burners	0.01 lb/MMBtu, normal operation
LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR • Auxiliary Boiler	1100 MMBtu/hr	SCR	0.014 lb/MMBtu, 12-month rolling avg
LA-0394	SHELL CHEMICAL GEISMAR PLANT	LA	12/12/2023	01-22 • A0-5 Boiler	350 MMBtu/hr	SCR	0.011 lb/MMBtu, 30-day rolling avg
TX-0936	VALERO BILL GREEHEY REFINERY	TX	3/29/2022	BOILER	334 MMBtu/hr	None listed	
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	SCR & LNB	0.01 lb/MMBtu, 12-month rolling avg
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 MMBtu/hr	None listed	0.052 lb/MMBtu
	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 MMBtu/hr	None listed	0.123 lb/MMBtu on a 3-hour avg
MI-0440	MICHIGAN STATE UNIVERSITY*	MI	5/22/2019	EUSTMBoiler	300 MMBtu/hr	Low NOx Burners and FGR	0.04 lb/MMBtu, 30-day rolling avg (natural gas) 0.07 lb/MMBtu, 30-day rolling avg (fuel oil)
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Auxiliary Boller	773 MMBtu/hr	Good combustion practices	
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 • Boiler 1 (EQT0003)	350 MMBtu/hr	SCR, LNB, good combustion practices	0.01 lb/MMBtu, 12-month rolling avg
	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 • Boiler 2 (EQT0004)	350 MMBtu/hr	SCR, LNB, good combustion practices	0.01 lb/MMBtu, 12-month rolling avg

Original construction dates 1970, modified in 2019

* Uses No 2 fuel oil as backup

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS

LARGE NATURAL GAS FIRED BOILERS (Process code 11.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - CO	EMISSION LIMIT - CO
LA-0406	MCA GEIMAR SITE	LA	7/24/2024	CO MeOH Auxiliary Boiler (EQT0001)	321 MMBtu/hr	CO oxidation catalyst, compliance with MACT Subpart DDDDD	5 ppm, annual avg
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	TX	2/5/2024	Auxiliary Boiler	>250 MMBtu/hr	Good combustion practices, proper maintenance	0.037 lb/MMBtu, normal operation
LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR • Auxiliary Boiler	1100 MMBtu/hr	Good combustion practices	0.044 lb/MMBtu
LA-0394	SHELL CHEMICAL GEISMAR PLANT	LA	12/12/2023	01-22 • A0-5 Boiler	350 MMBtu/hr	Good operating practices	0.037 lb/MMBtu
TX-0936	VALERO BILL GREEHEY REFINERY	TX	3/29/2022	BOILER	334 MMBtu/hr	Gaseous fuel and good combustion practices	50 ppm
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Good combustion practices and compliance with 40 CFR 63, Subpart DDDDD	0.037 lb/MMBtu
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 MMBtu/hr	None listed	118.8 tpy
	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 MMBtu/hr	None listed	38 tpy, limited use
MI-0440	MICHIGAN STATE UNIVERSITY*	MI	5/22/2019	EUSTM Boiler	300 MMBtu/hr	Good combustion practices	0.05 lb/MMBtu
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Auxiliary Boller	773 MMBtu/hr	Good combustion practices	
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 • Boiler 1 (EQT0003)	350 MMBtu/hr	Good combustion practices	0.038 lb/MMBtu
	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 • Boiler 2 (EQT0004)	350 MMBtu/hr	Good combustion practices	0.038 lb/MMBtu

Original construction dates 1970, modified in 2019

* Uses No 2 fuel oil as backup

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS

LARGE NATURAL GAS FIRED BOILERS (Process code 11.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - SO2	EMISSION LIMIT - SO2
LA-0406	MCA GEIMAR SITE	LA	7/24/2024	CO MeOH Auxiliary Boiler (EQT0001)	321 MMBtu/hr	N/A	
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	TX	2/5/2024	Auxiliary Boiler	>250 MMBtu/hr	N/A	
LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR • Auxiliary Boiler	1100 MMBtu/hr	N/A	
LA-0394	SHELL CHEMICAL GEISMAR PLANT	LA	12/12/2023	01-22 • A0-5 Boiler	350 MMBtu/hr	N/A	
TX-0936	VALERO BILL GREEHEY REFINERY	TX	3/29/2022	BOILER	334 MMBtu/hr	N/A	
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Use of pipeline quality natural gas	0.0006 lb/MMBtu
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 MMBtu/hr	N/A	
	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 MMBtu/hr	N/A	
MI-0440	MICHIGAN STATE UNIVERSITY*	MI	5/22/2019	EUSTMBOILER	300 MMBtu/hr	N/A	
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Auxiliary Boller	773 MMBtu/hr	Good combustion practices	
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 • Boiler 1 (EQT0003)	350 MMBtu/hr	N/A	
	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 • Boiler 2 (EQT0004)	350 MMBtu/hr	N/A	

Original construction dates 1970, modified in 2019

* Uses No 2 fuel oil as backup

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

EXISTING COAL TO GAS CONVERSIONS

FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - PM	EMISSION LIMIT (or FACTOR) - PM
Nevada Power Company dba Nevada Energy	NV	7/2/2024 (app submittal date, not final)	North Valmy Generating Station - Unit 1	2708 MMBtu/hr	Pipeline quality natural gas	0.0075 lb/MMBtu
			North Valmy Generating Station - Unit 2	3048 MMBtu/hr	Pipeline quality natural gas	0.0075 lb/MMBtu
PacifiCorp Energy	WY	4/3/25 (app submittal date, not yet issued)	Naughton Unit 1	1850 MMBtu/hr	Pipeline quality natural gas	0.005 lb/MMBtu
			Naughton Unit 2	2400 MMBtu/hr	Pipeline quality natural gas	0.005 lb/MMBtu
PacifiCorp Energy	WY	12/28/2022	Bridger Unit 1	3000 MMBtu/hr	Pipeline quality natural gas	0.012 lb/MMBtu
			Bridger Unit 2	3000 MMBtu/hr	Pipeline quality natural gas	0.012 lb/MMBtu
Midwest Generation, LLC	IL	10/16/2015	Unit 6	3543 MMBtu/hr	N/A	
			Unit 7 (two boilers, combined capacity)	6034 MMBtu/hr	N/A	
			Unit 8 (two boilers, combined capacity)	6384 MMBtu/hr	N/A	

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

EXISTING COAL TO GAS CONVERSIONS

FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - NOx	EMISSION LIMIT (or FACTOR) - NOx
Nevada Power Company dba Nevada Energy	NV	7/2/24 (app submittal date, not final)	North Valmy Generating Station - Unit 1	2708 MMBtu/hr	LNB	0.137 lb/MMBtu
			North Valmy Generating Station - Unit 2	3048 MMBtu/hr	LNB	0.137 lb/MMBtu
PacifiCorp Energy	WY	4/3/25 (app submittal date, not yet issued)	Naughton Unit 1	1850 MMBtu/hr	LNB	0.12 lb/MMBtu on a rolling 30-day avg
			Naughton Unit 2	2400 MMBtu/hr	LNB	0.12 lb/MMBtu on a rolling 30-day avg
PacifiCorp Energy	WY	12/28/2022	Bridger Unit 1	3000 MMBtu/hr	LNB	0.12 lb/MMBtu on a rolling 30-day avg
			Bridger Unit 2	3000 MMBtu/hr	LNB	0.12 lb/MMBtu on a rolling 30-day avg
Midwest Generation, LLC	IL	10/16/2015	Unit 6	3543 MMBtu/hr	OFA and gas reburn	0.135 lb/MMBtu on a rolling 30-day avg
			Unit 7 (two boilers, combined capacity)	6034 MMBtu/hr	LNB and OFA	0.110 lb/MMBtu on a rolling 30-day avg
			Unit 8 (two boilers, combined capacity)	6384 MMBtu/hr	LNB and OFA	0.110 lb/MMBtu on a rolling 30-day avg

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

EXISTING COAL TO GAS CONVERSIONS

FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - CO	EMISSION LIMIT (or FACTOR) - CO
Nevada Power Company dba Nevada Energy	NV	7/2/2024 (app submittal date, not final)	North Valmy Generating Station - Unit 1	2708 MMBtu/hr	None listed	0.08 lb/MMBtu
			North Valmy Generating Station - Unit 2	3048 MMBtu/hr	None listed	0.08 lb/MMBtu
PacifiCorp Energy	WY	4/3/25 (app submittal date, not yet issued)	Naughton Unit 1	1850 MMBtu/hr	None listed	0.024 lb/MMBtu
			Naughton Unit 2	2400 MMBtu/hr	None listed	0.024 lb/MMBtu
PacifiCorp Energy	WY	12/28/2022	Bridger Unit 1	3000 MMBtu/hr	None listed	0.08 lb/MMBtu
			Bridger Unit 2	3000 MMBtu/hr	None listed	0.08 lb/MMBtu
Midwest Generation, LLC	IL	10/16/2015	Unit 6	3543 MMBtu/hr	N/A	
			Unit 7 (two boilers, combined capacity)	6034 MMBtu/hr	N/A	
			Unit 8 (two boilers, combined capacity)	6384 MMBtu/hr	N/A	

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

EXISTING COAL TO GAS CONVERSIONS

FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - SO2	EMISSION LIMIT (or FACTOR) - SO2
Nevada Power Company dba Nevada Energy	NV	7/2/2024 (app submittal date, not final)	North Valmy Generating Station - Unit 1	2708 MMBtu/hr	Pipeline quality natural gas	0.0056 lb/MMBtu
			North Valmy Generating Station - Unit 2	3048 MMBtu/hr	Pipeline quality natural gas	0.0056 lb/MMBtu
PacifiCorp Energy	WY	4/3/25 (app submittal date, not yet issued)	Naughton Unit 1	1850 MMBtu/hr	Pipeline quality natural gas	0.0006 lb/MMBtu
			Naughton Unit 2	2400 MMBtu/hr	Pipeline quality natural gas	0.0006 lb/MMBtu
PacifiCorp Energy	WY	12/28/2022	Bridger Unit 1	3000 MMBtu/hr	Pipeline quality natural gas	0.0006 lb/MMBtu
			Bridger Unit 2	3000 MMBtu/hr	Pipeline quality natural gas	0.0006 lb/MMBtu
Midwest Generation, LLC	IL	10/16/2015	Unit 6	3543 MMBtu/hr	N/A	
			Unit 7 (two boilers, combined capacity)	6034 MMBtu/hr	N/A	
			Unit 8 (two boilers, combined capacity)	6384 MMBtu/hr	N/A	

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.25

* NOTE: You must document why a retrofit factor of 1.25 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	723	MW
What is the higher heating value (HHV) of the fuel?	1,107	Btu/scf
What is the estimated actual annual MWhs output?	2,533,392	MWhs
Enter the net plant heat input rate (NPHR)	10.37	MMBtu/MW
Plant Elevation	220	Feet above sea level

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Number of days the SCR operates (t_{SCR})	175	days
Number of days the boiler operates (t_{plant})	175	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.12	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.042	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	17	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	330	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2023			
CEPCI for 2023	797.9	Enter the CEPCI value for 2023	541.7	2016 CEPCI
Annual Interest Rate (i)	7.5	Percent		
Reagent ($Cost_{reag}$)	2.445	$/gallon for 50% urea		
Electricity ($Cost_{elect}$)	0.0680	$/kWh		
Catalyst cost ($CC_{replace}$)	344.36	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	110.00	$/hour (including benefits)		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-	$2.445/gal, adjusted reagent cost using CEPCI value for 2023
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	0.068 $/kWh, https://www.eia.gov/state/print.php?sid=WA, industrial rate as of February 2025
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	HHV of 1107 Btu/scf from June 2024-May 2025 Williams Northwest Pipeline data averaged between Chehalis and Sumas compressor stations (north and south of Centralia)
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	$344.36/gal, adjusted catalyst cost using CEPCI value for 2023

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	7,498	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	6,333,480	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		2,533,392	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.04		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.400	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3504	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	65.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	584.81	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,024.58	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.81		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,471,334	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	23.26	/hour	
Residence Time	1/V_{space}	0.04	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.25		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1380	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	106,255.69	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,574	ft^2

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	15	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,960	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	54.4	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	96	feet

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	401	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	802	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	84	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	28,400	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1060

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	4112.55	kW

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers
For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:
$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$
For Oil and Natural Gas-Fired Utility Boilers >500 MW:
$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$
For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :
$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$
For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :
$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$
For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:
$TCI = 5,700 \times Q_B \times ELEVF \times RF$
For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:
$TCI = 7,640 \times Q_B \times ELEVF \times RF$

Total Capital Investment (TCI) =	$83,438,584	in 2023 dollars

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =		$3,803,766 in 2023 dollars
Indirect Annual Costs (IDAC) =		$8,851,806 in 2023 dollars
Total annual costs (TAC) = DAC + IDAC		$12,655,572 in 2023 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$417,193 in 2023 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$723,518 in 2023 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$979,906 in 2023 dollars
Annual Catalyst Replacement Cost =		$1,683,150 in 2023 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		$3,803,766 in 2023 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$7,316 in 2023 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$8,844,490 in 2023 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$8,851,806 in 2023 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =		$12,655,572 per year in 2023 dollars
NOx Removed =		1,025 tons/year
Cost Effectiveness =		$12,352 per ton of NOx removed in 2023 dollars

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Assumptions:

- Unit #2 is anticipated for actual operations to run at 40% capacity or less.
- Due to the extensive ductwork required for a retrofit (due to facility layout and existing structures), a retrofit factor of 1.25 was applied.
- The days of SCR and boiler operation include the 40% of annual hours (3504 hours, 146 days), assuming full load operation, plus the anticipated startup hours from 50 warm starts (50 starts is the contracturally cited number) at 840 min each, for a total of SCR/boiler operations at 175 days.
- The costs associated with actual retrofits are provided in EPA's Air Pollution Cost Control Manual, Section 4, Chapter 2 - NOx Controls, Selective Catalytic Reduction Table 2.1a - Summary of SCR Cost Data for Utility Boilers (June 2019)
  - -For Electric Generating Units, between 600-899 MW, the average SCR capital cost was $81/kW in 2004$ (these appear to be a mix of new and retrofits). For a 723 MW unit, that would be $58,563,000 in 2004$ and $105,195,000 in 2023$ scaled using the CEPCI
  - -For Electric Generating Units, between 400-800 MW, the average SCR capital cost was $420/kW in 2011$ (all are retrofits). For a 723 MW unit, that would be $303,660,000 in 2011$ and $413,676,473 in 2023$ scaled using the CEPCI
  - -The actual installation costs at utility boilers, including retrofits, far exceeds the anticipated capital cost using this EPA spreadsheet.
- The direct annual costs calculated by this spreadsheet are used for the other cost scenarios/configurations with their respective capital costs.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Unit 2 **SNCR** (based on actual 2012 installation costs for Unit #2)

Prime rate on 6/3/25	7.50%		
Duration of financing	17	years	
Capital Recovery Factor (CRF)[1]	0.106		
Capacity factor	59%		
Urea cost[2]	$515	per ton	in 2023$
Urea usage	2.6	gal/min (est)	
Urea density	9.49	lb/gal	

Capital Costs - SNCR assuming full relocation of all injection ports

Direct Costs (est)	$	16,287,000	
Indirect Costs (est)	$	3,713,000	
Total Installed Cost/Capital Investment (TCI)	**$**	**20,000,000**	in 2012$
	$	**27,297,297**	in 2023$

Annual Costs - SNCR

Maintenance (general nozzle maintenance)	$	75,000	
Operation (cost of urea)	$	1,971,296	
Direct Annual Costs (DAC)	**$**	**2,046,296**	
Indirect Annual Costs (IDAC)			
IDAC = CRF * TCI	$	2,893,514	
Total Annual Costs (TAC)			
TAC = DAC + IDAC	**$**	**4,939,809**	**in 2023$**

1 EPA Cost Control Manual,Section 1, Chapter 2, Table A.2; July 2020.

2 Based on EPA cost control estimate ($1.66/gal in 2016$ from the SCR Cost Manual Spreadsheet 2019) updated using the 2023 CEPCI value.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Transalta
Unit 2 **FGR**

Prime rate on 6/20/25		7.50%
Duration of financing		17 years
Capital Recovery Factor (CRF)[1]		0.106
Capacity factor		59%

Capital Costs - Flue Gas Recirculation		
Direct Costs	$	19,400,000
Indirect Costs	$	12,320,000
Total Installed Cost/Capital Investment (TCI)	**$**	**31,720,000**

Annual Costs - Flue Gas Recirculation		
Maintenance (assuming 3% of equipment cost)	$	75,000
Operation (auxiliary cost for the motors)	$	790,560
Direct Annual Costs (DAC)	**$**	**865,560**

Indirect Annual Costs (IDAC)		
IDAC = CRF * TCI	$	3,362,320

Total Annual Costs (TAC)		
TAC = DAC + IDAC	**$**	**4,227,880**

[1] EPA Cost Control Manual,Section 1, Chapter 2, Table A.2; July 2020.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

TransAlta Centralia - Unit #2, FGR Vendor quote

ACCOUNT	QTY	UNITS	UNIT RATE	AMOUNT	MH	LABOR	MATL
EQUIPMENT	2	EACH	1,250,000	2,500,000	4,828	700,000	1,800,000
PIPING	800	FT	625	500,000	1,897	275,000	225,000
DUCT	820	FT	4,878	4,000,000	7,586	1,100,000	2,900,000
CONCRETE	840	CY	1,964	1,650,000	8,772	1,272,000	378,000
PILING	40	EACH	7,500	300,000	1,379	200,000	100,000
STEEL	530	TONS	10,943	5,800,000	17,241	2,500,000	3,300,000
E&I	50,000		45	2,225,000	8,448	1,225,000	1,000,000
DCS	150	IO	1,500	225,000	0	0	225,000
INSULATION	28,000	SF	46	1,300,000	5,517	800,000	500,000
PAINT	5,000	SF	10	50,000	276	40,000	10,000
DEMO	1		850,000	850,000	5,517	800,000	50,000
CONSTRUCTION				**19,400,000**	**61,462**	**8,912,000**	**10,488,000**
ENGINEERING				2,500,000			
CONSTRUCTION MANAGEMENT				1,500,000			
CONSTRUCTION EQUIPMENT				1,000,000			
CONTINGENCY (30%)				7,320,000			
TOTAL INSTALLED COST				**31,720,000**			

Yearly Maintenance Costs:

Assuming 3% of the equipment cost on an annual basis, the maintenance would be $75,000/year.

Operation Costs:

Operation costs would be the auxiliary load for the motors. Assuming 750 kW (1000 hp) per fan, 60% capacity factor, and $0.10 /kw-hr; the annual operating cost would be $790,560/year.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Data Inputs

Select the type of oxidizer: Catalytic Oxidizer - Fixed Bed

Enter the following information for your emission source:

Composition of Inlet Gas Stream

Pollutant Name	Concentration (ppmv)	Lower Explosive Limit (LEL) (ppmv)*	Heat of Combustion (Btu/scf)	Molecular Weight
Carbon monoxide	146	125,000	310	28

Note: The lower explosion limit (LEL), heat of combustion and molecular weight for some commonly used VOC/HAP are provided in the table below. In addition, the heat of combustion to be entered in column D is a lower heating value (LHV), not a higher heating value (HHV).

Enter the design data for the proposed oxidizer:

Number of operating hours/year	5,168	hours/year	
Inlet volumetric flow rate(Q_{wi}) at 77°F and 1 atm.	1,770,219	scfm	
Pressure drop (ΔP)	23	inches of water*	* 23 inches of water is a default pressure drop for catalytic oxidizers. User should enter actual value, if known.
Motor/Fan Efficiency (ε)	60	percent*	* 60% is a default fan efficiency. User should enter actual value, if known.
Inlet Waste Gas Temperature (T_{wi})	330	°F	
Operating Temperature (T_{fi})	900	°F	* Note: Default value for Tfi is 900°F for catalytic oxidizers. Use actual value if known. Tfi for catalytic oxidizers is typically between 300 and 900°F.
Destruction and Removal Efficiency (DRE)	98	percent	
Estimated Equipment Life	17	Years	

Percent Energy Recovery (HR) = 70 percent

Catalyst Data:

Estimated catalyst life (y)	4	years	* 4 years is a default value. User should enter actual value, if known.
Catalyst Unit Cost (CC)	888	$/ft^3	
Space velocity for catalyst (Φ)	30,000	/hour	* 30,000 per hour is a default value. User should enter actual value, if known.

Enter the cost data:

Desired dollar-year	2023				
CEPCI* for 2023	797.9	Enter the CEPCI value for 2023	390.6	1999 CEPCI	*Enter dollar year first.
Annual Interest Rate (i)	7.50	%			
Electricity ($Cost_{elect}$)	0.068	$/kWh			
Natural Gas Fuel Cost ($Cost_{fuel}$)	0.01428	$/scf			
Operator Labor Rate	$70.00	per hour			
Maintenance Labor rate	$70.00	per hour			
Contingency Factor (CF)	10.0	Percent			* 10 percent of the total capital investment F45 is a default value for construction contingencies. User may enter values between 5 and 15 percent.

* CEPCI is the Chemical Engineering Plant Cost Escalation/De-escalation Index. The use of CEPCI in this spreadsheet is not an endorsement of the index for purposes of cost escalation or de-escalation, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Parameters for Common Compounds:

Compound	LEL (ppmv)	Heat of Combustion (Btu/scf)	Molecular Weight
Methane*	50,000	911	16.04
Ethane	30,000	1,631	30.07
Propane	21,000	2,353	44.09
Butane	19,000	3,101	58.12
Pentane	14,000	3,709	72.15
Hexane	11,000	4,404	86.17
Octane	10,000	5,796	114.23
Nonane	8,000	6,493	128.25
Decane	8,000	7,190	142.28

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Ethylene**	27,000	1,499	28.05
Propylene	20,000	2,182	42.08
Cyclohexane	13,000	4,180	84.16
Benzene**	14,000	3,475	78.11
Toluene**	11,000	4,274	92.14
Methyl Chloride (Chloromethane)**	82,500	705	50.49
Footnotes * Greenhouse gas. ** Hazardous air pollutant.			

Data Element	Default Value	Sources for Default Values used in the calculation . . .	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Catalyst Cost ($/ft^3)	650	Based on 2014 vendor data for base metal oxide catalyst.	$888, used consumer price index inflation calculator (https://www.bls.gov/data/inflation_calculator.htm) to update December 2014 data to April 2025	Check with catalyst vendor.
Electricity Cost ($/kWh)	0.0641	Average annual electricity cost for industrial plants is based on 2016 price data compiled by the U.S. Energy Information Administration from data reported on Form EIA-861 and 861S, (https://www.eia.gov/electricity/annual/html/epa_02_04.html).	$0.068/kWh, https://www.eia.gov/state/print.php?sid=WA, industrial rate in Washington as of February 2025	Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/Mscf)	3.51	Annual average price paid for natural gas by industrial facilities in 2016 from the U.S. Energy Information Administration. Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.	14.28 $/Mscf - March 2025 rate for industrial facilities in Washington https://www.eia.gov/dnav/ng/hist/n3035wa3m.htm	Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.
Operator Labor ($/hour)	26.61	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for operators based on data for plant and System Operators – other (51-8099).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.
Maintenance Labor ($/hour)	27.40	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for maintenance workers based on electrical and electronics commercial and industrial equipment repairers (49-2094).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Design Parameters

The following design parameters for the oxidizer were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Composition of Inlet Gas Stream		
Pollutant Name	Concentration in Waste Stream (ppmv) From Data Inputs Tab	Adjusted Concentration with Dilution Air (ppmv)
Carbon monoxide	146	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
Total	146	0

Constants used in calculations:

Temperature of auxiliary fuel (T_{af}) =	Reference Temperature (T_{ref}) =	77.0	°F
Density of auxiliary Fuel at 77 °F (ρ_{af}) =		0.0408	lb/ft^3
Heat Input of auxiliary fuel ($-\Delta h_{caf}$) =		21,502	Btu/lb
Density of waste gas at 77 °F (ρ_{wi}) =		0.0739	lb/ft^3
Mean Heat Capacity of Air (C_{pmair}) =	(For catalytic oxidizers)	0.248	Btu/lb °F

Parameter	Equation	Calculated Value	Units	Value	Units
Sum of volume fraction of combustible components =	= ($\sum x_i$) =	146	ppmv		
Lower Explosive Limit of waste gas (LEL_{mix})	= $[\sum((x_j)/((\sum x_i) \times LEL_j))]^{-1}$ =	125,000	ppmv		
	Where x_j is the volume fraction and LEL_j the lower explosive limit for each combustible component in the waste gas.				
% LEL_{mix}	= (Total Combustible Conc. In Mixture/LEL_{mix}) × 100 =	0.12	percent	* Note: Since the LEL of the waste gas stream is below 25%, no dilution air is needed.	
Dilution Factor	= (LEL_{mix} x 0.249)/($\sum x_i$) =	Not applicable			
Lower Explosive Limit (LEL) of waste gas after addition of dilution air	= (Total Adjusted Conc. With Dilution Air/LEL_{mix}) × 100 =	Not Applicable			
Inlet volumetric flow rate(Qwi) at 77°F and 1 atm.	(From Data Entry Tab) =	1,770,219	scfm		
Oxygen Content of gas stream	= 100 - ($\sum x_j \times 100/10^6$) =	20.90	percent		
Fan Power Consumption (FP)	= $[(1.17 \times 10^{-4}) \times Q_{wi} \times \Delta P]/\varepsilon$	7939.4	kW		
Q_{wo}	≈ Q_{wi} =	1,770,219	scfm		
Operating temperature of oxidizer (T_{fi})	(From Data Entry Tab)	900	°F		
Temperature of waste gas at outlet to preheater (T_{wo})	= Heat Recovery × (T_{fi} - T_{wi}) + T_{wi} =	729	°F	Note: this temperature is relevant for incinerators, but not for t	
Temperature of flue gas exiting the oxidizer (T_{fo})	= T_{fi} - T_{wo} + T_{wi} =	501	°F		

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Heat Input of waste gas ($-\Delta h_{cwi}$)				
	$= \sum (-\Delta h_{ci})\ x_i$			
	Where $(-\Delta h_{ci})$ is the heat of combustion and x_i the fraction of component "i" at 77 °F.	0.05	Btu/scf	0.6 Btu/lb
Estimated Auxiliary Fuel Flow (Q_{af}) at 77 °F and 1 atm.	(Calculated using Equation 2.21 in Chapter 2 of the Cost Manual)	9,373.96	scfm	
Auxiliary fuel Energy Input =		8,223,599	Btu/min	
Minimum Energy required for combustion stabilization =	$= 5\% \times$ Total Energy Input $= 0.05 \times \rho_{fi} \times Q_{fi} \times C_{pmfi} \times (T_{fi} - T_{ref}) =$	1,379,987	Btu/min	
Is the calculated auxiliary fuel sufficient to stabilize combustion?	(Note: If the			
auxiliary fuel energy input > 5% of Total Energy Input, then the auxilary fuel is sufficient.)		Yes		
Auxiliary fuel flow (Qaf) at 77°F and 1 atm. =		9,374	scfm	
Total Volumetric Throughput (Q_{tot}) at 77 °F and 1 atm.	$= Q_{fi} = Q_{wo} + Q_a + Q_{af} = Q_{wi} + Q_{af} =$	1,779,593	scfm	

Calculation of Catalyst Volume and Estimated Temperature of Waste Gas Entering the Catalyst Bed

Volumetric Flow Rate at 60 °F and 1 atm (Q_{ft})	$= Q_{tot} \times (519)/(77\ °F + 460) =$	1,719,942	scfm
Catalyst Volume (Vol_{cat})	Where Q_{ft} is the volumetric flow rate of the waste gas (Q_{fi}) corrected to 60 °F and 1	3439.88	ft^3
Estimated inlet temperature to the catalyst bed (T_{ri}) =	(Calculated using Equation 2.28 in Chapter 2 of the Cost Manual)	898	°F

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\ (1+i)^n/(1+i)^n - 1 =$	0.1060
	Where n = Equipment Life and i= Interest Rate	

Future Worth Factor

Parameter	Equation	Calculated Value
Future Worth Factor (FWF) =	$i\ [1/(1+i)^y - 1] =$	0.2236
	Where y = Catalyst Life and i= Interest Rate	

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Cost Estimate

Direct Costs			
Total Purchased equipment costs (in 2023 dollars)			
Incinerator + auxiliary equipment[a] (A) = Equipment Costs (EC) for Fluid Bed Catalytic Oxidizer			in 2023 dollars
Instrumentation[b] =	0.10 × A =	$839,527	
Sales taxes =	0.03 × A =	$251,858	
Freight =	0.05 × A =	$419,764	
	Total Purchased equipment costs (B) =	$9,906,422	in 2023 dollars

Footnotes
a - Auxiliary equipment includes equipment (e.g., duct work) normally not included with unit furnished by incinerator vendor.
b - Includes the instrumentation and controls furnished by the incinerator vendor.

Direct Installation Costs (in 2023 dollars)			
Foundations and Supports =	0.08 × B =	$792,514	
Handling and Erection =	0.14 × B =	$1,386,899	
Electrical =	0.04 × B =	$396,257	
Piping =	0.02 × B =	$198,128	
Insulation for Ductwork =	0.01 × B =	$99,064	
Painting =	0.01 × B =	$99,064	
Site Preparation (SP) =		$0	
Buildings (Bldg) =		$0	
	Total Direct Installaton Costs =	$2,971,926	
Total Direct Costs (DC) =	B + C + SP + Bldg =	$12,878,348	in 2023 dollars
Total Indirect Installation Costs (in 2023 dollars)			
Engineering =	0.10 × B =	$990,642	
Construction and field expenses =	0.05 × B =	$495,321	
Contractor fees =	0.10 × B =	$990,642	
Start-up =	0.02 × B =	$198,128	
Performance test =	0.01 × B =	$99,064	
	Total Indirect Costs (IC) =	$2,773,798	
Continency Cost (C) =	CF(IC+DC)=	$1,565,215	
Total Capital Investment =	**DC + IC +C =**	**$17,217,361**	**in 2023 dollars**

Direct Annual Costs

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Catalyst Replacement Cost	= 1.08 × CC × Vol_{cat} × FWF Where CC is the $/ft^3 cost for the replacement catalyst; Vol_{cat} is the volume of catalyst required based on the waste gas flow rate (Q_{ft}) and the catalyst space velocity (Φ); and FWF is the future worth factor.	$737,546
Annual Electricity Cost	= Annual Electricity Usage × Operating Hours/year × Electricity Price =	$2,790,107
Annual Fuel Costs for Natural Gas	= $Cost_{fuel}$ × Fuel Usage Rate × 60 min/hr × Operating hours/year	$41,507,336
Operating Labor	Operator = 0.5hours/shift × Labor Rate × (Operating hours/8 hours/shift)	$22,610
	Supervisor = 15% of Operator	$3,392
Maintenance Costs	Labor = 0.5 hours/shift × Labor Rate × (Operating Hours/8 hours/shift)	$22,610
	Materials = 100% of maintenance labor	$22,610
Direct Annual Costs (DC) =		**$45,106,211 in 2023 dollars**

Indirect Annual Costs

Overhead	= 60% of sum of operating, supervisor, maintenance labor and maintenance materials	$42,733
Administrative Charges	= 2% of TCI	$344,347
Property Taxes	= 1% of TCI	$172,174
Insurance	= 1% of TCI	$172,174
Capital Recovery	= CRF[TCI-1.08(cat. Cost)]	$1,740,606
Indirect Annual Costs (IC) =		**$2,472,034 in 2023 dollars**
Total Annual Cost =	**DC + IC =**	**$47,578,245 in 2023 dollars**

Cost Effectiveness

Cost Effectiveness = (Total Annual Cost)/(Annual Quantity of VOC/HAP Pollutants Destroyed)

Total Annual Cost (TAC) =	$47,578,245	per year in 2023 dollars
VOC/HAP Pollutants Destroyed =	2,844.8	tons/year
Cost Effectiveness =	$16,724	per ton of pollutants removed in 2023 dollars

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Data Inputs

Select the type of oxidizer: Catalytic Oxidizer - Fixed Bed

Enter the following information for your emission source:

Composition of Inlet Gas Stream

Pollutant Name	Concentration (ppmv)	Lower Explosive Limit (LEL) (ppmv)*	Heat of Combustion (Btu/scf)	Molecular Weight
Hexane	1	11,000	4,667	86
Formaldehyde	0	70,000	1,020	30
Butane	1	19,000	3,101	58

Note: The lower explosion limit (LEL), heat of combustion and molecular weight for some commonly used VOC/HAP are provided in the table below. In addition, the heat of combustion to be entered in column D is a lower heating value (LHV), not a higher heating value (HHV).

Enter the design data for the proposed oxidizer:

Number of operating hours/year	5,168	hours/year	
Inlet volumetric flow rate(Q_{wi}) at 77°F and 1 atm.	1,770,219	scfm	
Pressure drop (ΔP)	23	inches of water*	* 23 inches of water is a default pressure drop for catalytic oxidizers. User should enter actual value, if known.
Motor/Fan Efficiency (ε)	60	percent*	* 60% is a default fan efficiency. User should enter actual value, if known.
Inlet Waste Gas Temperature (T_{wi})	330	°F	
Operating Temperature (T_{fi})	900	°F	* Note: Default value for Tfi is 900°F for catalytic oxidizers. Use actual value if known. Tfi for catalytic oxidizers is typically between 300 and 900°F.
Destruction and Removal Efficiency (DRE)	99	percent*	* 99 percent is a default control efficiency. User should enter actual value, if known.
Estimated Equipment Life	17	Years	

Percent Energy Recovery (HR) = 70 percent

0
35
50
70

Catalyst Data:

Estimated catalyst life (y)	4	years	* 4 years is a default value. User should enter actual value, if known.
Catalyst Unit Cost (CC)	888	$/ft³	
Space velocity for catalyst (Φ)	30,000	/hour	* 30,000 per hour is a default value. User should enter actual value, if known.

Enter the cost data:

Desired dollar-year	2023				
CEPCI* for 2023	797.9	Enter the CEPCI value for 2023	390.6	1999 CEPCI	*Enter dollar year first.
Annual Interest Rate (i)	7.50	%			
Electricity ($Cost_{elect}$)	0.068	$/kWh			
Natural Gas Fuel Cost ($Cost_{fuel}$)	0.01428	$/scf			
Operator Labor Rate	$70.00	per hour			
Maintenance Labor rate	$70.00	per hour			
Contingency Factor (CF)	10.0	Percent			* 10 percent of the total capital investment F45is a default value for construction contingencies. User may enter values between 5 and 15 percent.

* CEPCI is the Chemical Engineering Plant Cost Escalation/De-escalation Index. The use of CEPCI in this spreadsheet is not an endorsement of the index for purposes of cost escalation or de-escalation, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Parameters for Common Compounds:

Compound	LEL (ppmv)	Heat of Combustion (Btu/scf)	Molecular Weight
Methane*	50,000	911	16.04
Ethane	30,000	1,631	30.07
Propane	21,000	2,353	44.09
Butane	19,000	3,101	58.12
Pentane	14,000	3,709	72.15

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Hexane	11,000	4,404	86.17
Octane	10,000	5,796	114.23
Nonane	8,000	6,493	128.25
Decane	8,000	7,190	142.28
Ethylene**	27,000	1,499	28.05
Propylene	20,000	2,182	42.08
Cyclohexane	13,000	4,180	84.16
Benzene**	14,000	3,475	78.11
Toluene**	11,000	4,274	92.14
Methyl Chloride (Chloromethane)**	82,500	705	50.49
Footnotes * Greenhouse gas. ** Hazardous air pollutant.			

Data Element	Default Value	Sources for Default Values used in the calculation . . .	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Catalyst Cost ($/ft^3)	650	Based on 2014 vendor data for base metal oxide catalyst.	$888, used consumer price index inflation calculator (https://www.bls.gov/data/inflation_calculator.htm) to update December 2014 data to April 2025	Check with catalyst vendor.
Electricity Cost ($/kWh)	0.0641	Average annual electricity cost for industrial plants is based on 2016 price data compiled by the U.S. Energy Information Administration from data reported on Form EIA-861 and 861S, (https://www.eia.gov/electricity/annual/html/epa_02_04.html).	$0.068/kWh, https://www.eia.gov/state/print.php?sid=WA, industrial rate in Washington as of February 2025	Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/Mscf)	3.51	Annual average price paid for natural gas by industrial facilities in 2016 from the U.S. Energy Information Administration. Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.	14.28 $/Mscf - March 2025 rate for industrial facilities in Washington https://www.eia.gov/dnav/ng/hist/n3035wa3m.htm	Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.
Operator Labor ($/hour)	26.61	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for operators based on data for plant and System Operators – other (51-8099).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.
Maintenance Labor ($/hour)	27.40	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for maintenance workers based on electrical and electronics commercial and industrial equipment repairers (49-2094).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Design Parameters

The following design parameters for the oxidizer were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Composition of Inlet Gas Stream		
Pollutant Name	Concentration in Waste Stream (ppmv) From Data Inputs Tab	Adjusted Concentration with Dilution Air (ppmv)
Hexane	1	NA
Formaldehyde	0	NA
Butane	1	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
Total	1	0

Constants used in calculations:

Temperature of auxiliary fuel (T_{af}) =	Reference Temperature (T_{ref}) =	77.0	°F
Density of auxiliary Fuel at 77 °F (ρ_{af}) =		0.0408	lb/ft^3
Heat Input of auxiliary fuel ($-\Delta h_{caf}$) =		21,502	Btu/lb
Density of waste gas at 77 °F (ρ_{wi}) =		0.0739	lb/ft^3
Mean Heat Capacity of Air (C_{pmair}) =	(For catalytic oxidizers)	0.248	Btu/lb °F

Parameter	Equation	Calculated Value	Units	Value	Units
Sum of volume fraction of combustible components =	= $(\sum x_i)$ =	1	ppmv		
Lower Explosive Limit of waste gas (LEL_{mix})	= $[\sum((x_j)/((\sum x_i) \times LEL_j))]^{-1}$ =	15,319	ppmv		
	Where x_j is the volume fraction and LEL_j the lower explosive limit for each combustible component in the waste gas.				
% LEL_{mix}	= (Total Combustible Conc. In Mixture/LEL_{mix}) × 100 =	0.01	percent	* Note: Since the LEL of the waste gas stream is below 25%, no dilution air is needed.	
Dilution Factor	= (LEL_{mix} x 0.249)/$(\sum x_i)$ =	Not applicable			
Lower Explosive Limit (LEL) of waste gas after addition of dilution air	= (Total Adjusted Conc. With Dilution Air/LEL_{mix}) × 100 =	Not Applicable			
Inlet volumetric flow rate(Qwi) at 77°F and 1 atm.	(From Data Entry Tab) =	1,770,219	scfm		
Oxygen Content of gas stream	= 100 - $(\sum x_j \times 100/10^6)$ =	20.90	percent		
Fan Power Consumption (FP)	= $[(1.17 \times 10^{-4}) \times Q_{wi} \times \Delta P]/\varepsilon$	7939.4	kW		
Q_{wo}	≈ Q_{wi} =	1,770,219	scfm		
Operating temperature of oxidizer (T_{fi})	(From Data Entry Tab)	900	°F		
Temperature of waste gas at outlet to preheater (T_{wo})	= Heat Recovery × (T_{fi} - T_{wi}) + T_{wi} =	729	°F	Note: this temperature is relevant for incinerators, but not for th	
Temperature of flue gas exiting the oxidizer (T_{fo})	= T_{fi} - T_{wo} + T_{wi} =	501	°F		
Heat Input of waste gas ($-\Delta h_{cwi}$)					
	= $\sum(-\Delta h_{ci})\, x_i$ Where $(-\Delta h_{ci})$ is the heat of combustion and x_i the fraction of component "i" at 77 °F.	0.00	Btu/scf	0.1	Btu/lb

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Estimated Auxiliary Fuel Flow (Q_{af}) at 77 °F and 1 atm.	(Calculated using Equation 2.21 in Chapter 2 of the Cost Manual)	9,457.42 scfm
Auxiliary fuel Energy Input =		8,296,824 Btu/min
Minimum Energy required for combustion stabilization =	= 5% × Total Energy Input = $0.05 \times \rho_{fi} \times Q_{fi} \times C_{pmfi} \times (T_{fi} - T_{ref})$ =	1,380,052 Btu/min
Is the calculated auxiliary fuel sufficient to stabilize combustion? (Note: If the auxiliary fuel energy input > 5% of Total Energy Input, then the auxilary fuel is sufficient.)		Yes
Auxiliary fuel flow (Qaf) at 77°F and 1 atm. =		9,457 scfm
Total Volumetric Throughput (Q_{tot}) at 77 °F and 1 atm.	$= Q_{fi} = Q_{wo} + Q_a + Q_{af} = Q_{wi} + Q_{af}$ =	1,779,676 scfm

Calculation of Catalyst Volume and Estimated Temperature of Waste Gas Entering the Catalyst Bed

Volumetric Flow Rate at 60 °F and 1 atm (Q_{ft})	$= Q_{tot} \times (519)/(77\ °F + 460)$ =	1,720,022 scfm
Catalyst Volume (Vol_{cat})	Where Q_{ft} is the volumetric flow rate of the waste gas (Q_{fi}) corrected to 60 °F and 1	3440.04 ft^3
Estimated inlet temperature to the catalyst bed (T_{ri}) =	(Calculated using Equation 2.28 in Chapter 2 of the Cost Manual)	900 °F

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1060

Future Worth Factor

Parameter	Equation	Calculated Value
Future Worth Factor (FWF) =	$i\,[1/(1+i)^y - 1]$ = Where y = Catalyst Life and i= Interest Rate	0.2236

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Cost Estimate

Direct Costs			
Total Purchased equipment costs (in 2023 dollars)			
Incinerator + auxiliary equipment[a] (A) =			
Equipment Costs (EC) for a Fixed Bed Catalytic Oxidizer	= (1,443 x Qtot^(0.5527)) x (2023 CEPI/1999 CEPCI) =	$8,395,490	in 2023 dollars
Instrumentation[b] =	0.10 × A =	$839,549	
Sales taxes =	0.03 × A =	$251,865	
Freight =	0.05 × A =	$419,775	
	Total Purchased equipment costs (B) =	$9,906,678	in 2023 dollars

Footnotes
a - Auxiliary equipment includes equipment (e.g., duct work) normally not included with unit furnished by incinerator vendor.
b - Includes the instrumentation and controls furnished by the incinerator vendor.

Direct Installation Costs (in 2023 dollars)			
Foundations and Supports =	0.08 × B =	$792,534	
Handling and Erection =	0.14 × B =	$1,386,935	
Electrical =	0.04 × B =	$396,267	
Piping =	0.02 × B =	$198,134	
Insulation for Ductwork =	0.01 × B =	$99,067	
Painting =	0.01 × B =	$99,067	
Site Preparation (SP) =		$0	
Buildings (Bldg) =		$0	
	Total Direct Installaton Costs =	$2,972,003	
Total Direct Costs (DC) =	B + C + SP + Bldg =	$12,878,682	in 2023 dollars

Total Indirect Installation Costs (in 2023 dollars)			
Engineering =	0.10 × B =	$990,668	
Construction and field expenses =	0.05 × B =	$495,334	
Contractor fees =	0.10 × B =	$990,668	
Start-up =	0.02 × B =	$198,134	
Performance test =	0.01 × B =	$99,067	
	Total Indirect Costs (IC) =	$2,773,870	
Continency Cost (C) =	CF(IC+DC)=	$1,565,255	
Total Capital Investment =	**DC + IC +C =**	**$17,217,807**	**in 2023 dollars**

Direct Annual Costs

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Catalyst Replacement Cost	= 1.08 × CC × Vol_{cat} × FWF Where CC is the $/ft^3 cost for the replacement catalyst; Vol_{cat} is the volume of catalyst required based on the waste gas flow rate (Q_{ft}) and the catalyst space velocity (Φ); and FWF is the future worth factor.	$737,581
Annual Electricity Cost	= Annual Electricity Usage × Operating Hours/year × Electricity Price =	$2,790,107
Annual Fuel Costs for Natural Gas	= $Cost_{fuel}$ × Fuel Usage Rate × 60 min/hr × Operating hours/year	$41,876,927
Operating Labor	Operator = 0.5hours/shift × Labor Rate × (Operating hours/8 hours/shift)	$22,610
	Supervisor = 15% of Operator	$3,392
Maintenance Costs	Labor = 0.5 hours/shift × Labor Rate × (Operating Hours/8 hours/shift)	$22,610
	Materials = 100% of maintenance labor	$22,610
Direct Annual Costs (DC) =		**$45,475,836 in 2023 dollars**

Indirect Annual Costs

Overhead	= 60% of sum of operating, supervisor, maintenance labor and maintenance materials	$42,733
Administrative Charges	= 2% of TCI	$344,356
Property Taxes	= 1% of TCI	$172,178
Insurance	= 1% of TCI	$172,178
Capital Recovery	= CRF[TCI-1.08(cat. Cost)]	$1,740,650
Indirect Annual Costs (IC) =		**$2,472,095 in 2023 dollars**
Total Annual Cost =	**DC + IC =**	**$47,947,931 in 2023 dollars**

Cost Effectiveness

Cost Effectiveness = (Total Annual Cost)/(Annual Quantity of VOC/HAP Pollutants Destroyed)

Total Annual Cost (TAC) =	$47,947,931 per year in 2023 dollars
VOC/HAP Pollutants Destroyed =	57.2 tons/year
Cost Effectiveness =	$838,100 per ton of pollutants removed in 2023 dollars

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS

INDUSTRIAL-SIZE NATURAL GAS FIRED BOILERS (Between 100 and 250 MMBtu/hr, Process code 12.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - PM	EMISSION LIMIT - PM	EMISSION LIMIT - PM2.5
IN-0382	DUKE ENERGY INDIANA - CAYUGA GENERATING STATION	IN	2/14/2025	Auxiliary Boiler	225 MMBtu/hr	Good combustion practices and pipeline quality natural gas	0.0019 lb/MMBtu	
IN-0371	WABASH VALLEY RESOURCES	IN	1/11/2024	Auxiliary Boiler - Unit 1C	217.65 MMBtu/hr	None		
IL-0134	CRONUS CHEMICALS, LLC	IL	12/21/2023	Boiler	179.4 MMBtu/hr	Good combustion practices	0.0019 lb/MMBtu	0.001 lb/MMBtu
OH-0391	VALENCIA PROJECT LLC	OH	10/27/2023	Boiler #1 and 2	122 MMBtu/hr	Good combustion practices	0.0005 lb/MMBtu	0.0004 lb/MMBtu
LA-0397	INDORAMA VENTURES OLEFINS, LLC - WESTLAKE ETHYLENE	LA	4/29/2022	EQT0011	248 MMBtu/hr	None		
AK-0086	KENAI NITROGEN OPERATIONS	AK	3/26/2021	PKG Boiler	243 MMBtu/hr	Good combustion practices	0.0075 lb/MMBtu	
LA-0397	SHINTECH LOUISIANA LLC - PLAQUEMINE PLANT 3	LA	1/19/2021	Boiler D	250 MMBtu/hr	Good combustion practices	0.005 lb/MMBtu	
MI-0445	INDECK NILES, LLC	MI	11/26/2019	AuxBoiler	182 MMBtu/hr	Good combustion practices	0.007 lb/MMBtu	

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS

INDUSTRIAL-SIZE NATURAL GAS FIRED BOILERS (Between 100 and 250 MMBtu/hr, Process code 12.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - NOx	EMISSION LIMIT - NOx
IN-0382	DUKE ENERGY INDIANA - CAYUGA GENERATING STATION	IN	2/14/2025	Auxiliary Boiler	225 MMBtu/hr	Not listed	
IN-0371	WABASH VALLEY RESOURCES	IN	1/11/2024	Auxiliary Boiler - Unit 1C	217.65 MMBtu/hr	Low NOx burner and SCR with good combustion practices	0.01 lb/MMBtu
IL-0134	CRONUS CHEMICALS, LLC	IL	12/21/2023	Boiler	179.4 MMBtu/hr	LNB and SCR	0.01 lb/MMBtu
OH-0391	VALENCIA PROJECT LLC	OH	10/27/2023	Boiler #1 and 2	122 MMBtu/hr	None	
LA-0397	INDORAMA VENTURES OLEFINS, LLC - WESTLAKE ETHYLENE	LA	4/29/2022	EQT0011	248 MMBtu/hr	SCR, LNB, FGR	0.01 lb/MMBtu
AK-0086	KENAI NITROGEN OPERATIONS	AK	3/26/2021	PKG Boiler	243 MMBtu/hr	SCR	0.01 lb/MMBtu
LA-0397	SHINTECH LOUISIANA LLC - PLAQUEMINE PLANT 3	LA	1/19/2021	Boiler D	250 MMBtu/hr	LNB and SCR	0.01 lb/MMBtu
MI-0445	INDECK NILES, LLC	MI	11/26/2019	AuxBoiler	182 MMBtu/hr	LNB and FGR	0.04 lb/MMBtu

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS

INDUSTRIAL-SIZE NATURAL GAS FIRED BOILERS (Between 100 and 250 MMBtu/hr, Process code 12.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - CO	EMISSION LIMIT - CO
IN-0382	DUKE ENERGY INDIANA - CAYUGA GENERATING STATION	IN	2/14/2025	Auxiliary Boiler	225 MMBtu/hr	Good combustion practices	0.037 lb/MMBtu 3-hr avg
IN-0371	WABASH VALLEY RESOURCES	IN	1/11/2024	Auxiliary Boiler - Unit 1C	217.65 MMBtu/hr	None	
IL-0134	CRONUS CHEMICALS, LLC	IL	12/21/2023	Boiler	179.4 MMBtu/hr	Oxidation Catalyst	0.0013 lb/MMBtu
OH-0391	VALENCIA PROJECT LLC	OH	10/27/2023	Boiler #1 and 2	122 MMBtu/hr	None	
LA-0397	INDORAMA VENTURES OLEFINS, LLC - WESTLAKE ETHYLENE	LA	4/29/2022	EQT0011	248 MMBtu/hr	None	
AK-0086	KENAI NITROGEN OPERATIONS	AK	3/26/2021	PKG Boiler	243 MMBtu/hr	Good combustion practices	50 ppm
LA-0397	SHINTECH LOUISIANA LLC - PLAQUEMINE PLANT 3	LA	1/19/2021	Boiler D	250 MMBtu/hr	Good combustion practices	0.0362 lb/MMBtu
MI-0445	INDECK NILES, LLC	MI	11/26/2019	AuxBoiler	182 MMBtu/hr	Good combustion practices	0.04 lb/MMBtu

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

RBLC CLEARINGHOUSE LISTINGS

INDUSTRIAL-SIZE NATURAL GAS FIRED BOILERS (Between 100 and 250 MMBtu/hr, Process code 12.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - SO2	EMISSION LIMIT - SO2
IN-0382	DUKE ENERGY INDIANA - CAYUGA GENERATING STATION	IN	2/14/2025	Auxiliary Boiler	225 MMBtu/hr	None	
IN-0371	WABASH VALLEY RESOURCES	IN	1/11/2024	Auxiliary Boiler - Unit 1C	217.65 MMBtu/hr	None	
IL-0134	CRONUS CHEMICALS, LLC	IL	12/21/2023	Boiler	179.4 MMBtu/hr	None	
OH-0391	VALENCIA PROJECT LLC	OH	10/27/2023	Boiler #1 and 2	225 MMBtu/hr	None	
LA-0397	INDORAMA VENTURES OLEFINS, LLC - WESTLAKE ETHYLENE	LA	4/29/2022	EQT0011	248 MMBtu/hr	None	
AK-0086	KENAI NITROGEN OPERATIONS	AK	3/26/2021	PKG Boiler	243 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
LA-0397	SHINTECH LOUISIANA LLC - PLAQUEMINE PLANT 3	LA	1/19/2021	Boiler D	250 MMBtu/hr	Good combustion practices	0.0026 lb/MMBtu
MI-0445	INDECK NILES, LLC	MI	11/26/2019	AuxBoiler	182 MMBtu/hr	Good combustion practices	0.6 lb/MMSCF

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Natural Gas Dry

Safety Data Sheet

According To Federal Register / Vol. 77, No. 58 / Monday, March 26, 2012 / Rules And Regulations And According To The Hazardous Products Regulation (February 11, 2015).

Date of Issue: 08/16/2024 Version: 1.0

SECTION 1: IDENTIFICATION

1.1. Product Identifier

Product Form: Mixture

Product Name: Natural Gas Dry

Synonyms: Methane, Petroleum Gas, Methyl Hydride, Treated Gas, Process Gas

1.2. Intended Use of the Product

Fuel

1.3. Name, Address, and Telephone of the Responsible Party

Company

Williams Inc.
One Williams Center
Tulsa, OK 74172
855-945-5762
www.williams.com
ehs@williams.com

1.4. Emergency Telephone Number

CHEMTREC:
1-800-424-9300 (US/Canada)
+01 703-527-3887 (International)
Security.OperationsCenter@williams.com

SECTION 2: HAZARDS IDENTIFICATION

2.1. Classification of the Substance or Mixture

GHS-US/CA Classification

Flammable gases Category 1	H220
Gases under pressure Compressed gas	H280
Simple Asphyxiant	
Hazardous to the aquatic environment - Acute Hazard Category 3	H402
Hazardous to the aquatic environment - Chronic Hazard Category 3	H412

2.2. Label Elements

GHS-US/CA Labeling

Hazard Pictograms (GHS-US/CA) :



GHS02



GHS04

Signal Word (GHS-US/CA) : Danger

Hazard Statements (GHS-US/CA) :
H220 - Extremely flammable gas.
H280 - Contains gas under pressure; may explode if heated.
H402 - Harmful to aquatic life.
H412 - Harmful to aquatic life with long lasting effects.
May displace oxygen and cause rapid suffocation.

Precautionary Statements (GHS-US/CA) :
P210 - Keep away from heat, hot surfaces, sparks, open flames and other ignition sources. No smoking.
P273 - Avoid release to the environment.
P377 - Leaking gas fire: Do not extinguish, unless leak can be stopped safely.
P381 - In case of leakage, eliminate all ignition sources.
P403 - Store in a well-ventilated place.
P410+P403 - Protect from sunlight. Store in a well-ventilated place.
P501 - Dispose of contents/container in accordance with local, regional, national, territorial, provincial, and international regulations.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.3. Other Hazards

Exposure may aggravate pre-existing eye, skin, or respiratory conditions. Contact with gas escaping the container can cause frostbite.

2.4. Unknown Acute Toxicity (GHS-US/CA)

No additional information available

SECTION 3: COMPOSITION/INFORMATION ON INGREDIENTS

3.1. Substance

Not applicable

3.2. Mixture

Name	Synonyms	Product Identifier	% *	GHS Ingredient Classification
Natural gas, dried	Natural gas, dried (A complex combination of hydrocarbons separated from natural gas. It consists of saturated aliphatic hydrocarbons having carbon numbers in the range of C1-4, predominantly methane and ethane.) / Dry gas	(CAS-No.) 68410-63-9	100	Simple Asphy Flam. Gas 1, H220 Press. Gas (Comp.), H280
Ethanethiol	Ethyl mercaptan / Ethyl hydrosulfide / Ethyl sulfhydrate / Ethyl thioalcohol / Thioethanol / Thioethyl alcohol / ethanethiol	(CAS-No.) 75-08-1	< 0.1	Flam. Liq. 1, H224 Acute Tox. 4 (Oral), H302 Acute Tox. 4 (Inhalation:vapor), H332 Skin Sens. 1B, H317 Aquatic Acute 1, H400 Aquatic Chronic 1, H410

Full text of H-statements: see section 16

*Percentages are listed in weight by weight percentage (w/w%) for liquid and solid ingredients. Gas ingredients are listed in volume by volume percentage (v/v%).

SECTION 4: FIRST AID MEASURES

4.1. Description of First-aid Measures

General: Never give anything by mouth to an unconscious person. If you feel unwell, seek medical advice (show the label where possible).

Inhalation: First, take proper precautions to ensure your own safety before attempting rescue (e.g. wear appropriate respiratory protective equipment, use the buddy system), then remove the exposed person to fresh air. Keep at rest in a position comfortable for breathing. Give oxygen or artificial respiration if necessary. Obtain medical attention if breathing difficulty persists.

Skin Contact: Remove contaminated clothing. Drench affected area with water for at least 5 minutes. Obtain medical attention if irritation develops or persists. For brief contact with a small amount: Rewarm with body heat. Get immediate medical advice/attention. For extensive contact or a large amount: Immediately call a poison center/doctor and follow their advice. Specific treatment is urgent, incorrect first-aid practices will aggravate the injury. Protect affected area with a loose cover until proper medical treatment is received.

Eye Contact: Rinse cautiously with water for at least 5 minutes. Remove contact lenses, if present and easy to do. Continue rinsing. Obtain medical attention if irritation develops or persists.

Ingestion: Rinse mouth. Do NOT induce vomiting. Obtain medical attention.

4.2. Most Important Symptoms and Effects Both Acute and Delayed

General: Contact with gas escaping the container can cause frostbite. Asphyxia by lack of oxygen: risk of death.

Inhalation: In elevated concentrations may cause asphyxiation, central nervous system effects, and increased breathing rate. Symptoms of asphyxiation include headache, dizziness, rapid breathing, increased pulse, mood changes, tremors, cyanosis, muscular weakness, narcosis, numbness of the extremities, unconsciousness and death.

Skin Contact: Contact with gas escaping the container can cause frostbite and freeze burns.

Eye Contact: Contact with gas escaping the container can cause frostbite, freeze burns, and permanent eye damage.

Ingestion: Not considered a potential route of exposure, but contact with gas escaping the container can cause freeze burns and frostbite.

Chronic Symptoms: None known.

4.3. Indication of Any Immediate Medical Attention and Special Treatment Needed

If exposed or concerned, get medical advice and attention. If medical advice is needed, have product container or label at hand.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

SECTION 5: FIRE-FIGHTING MEASURES

5.1. Extinguishing Media

Suitable Extinguishing Media: Do not extinguish burning gas if flow cannot be shut off immediately. Extinguish secondary FIRES with appropriate materials.

Unsuitable Extinguishing Media: Do not use a heavy water stream. Use of heavy stream of water may spread fire.

5.2. Special Hazards Arising From the Substance or Mixture

Fire Hazard: Extremely flammable gas.

Explosion Hazard: May form flammable/explosive vapor-air mixture. Container may explode in heat of fire. Gas is heavier than air and may pool in low-lying areas and may drift towards ignition sources.

Reactivity: Hazardous reactions will not occur under normal conditions.

5.3. Advice for Firefighters

Precautionary Measures Fire: Exercise caution when fighting any chemical fire.

Firefighting Instructions: Use water spray or fog for cooling exposed containers. Leaking gas fire: Do not extinguish, unless leak can be stopped safely. Eliminate all ignition sources if safe to do so. Fight fire remotely due to the risk of explosion.

Protection During Firefighting: Do not enter fire area without proper protective equipment, including respiratory protection.

Hazardous Combustion Products: Hydrocarbons. Sulfur compounds.

Other Information: Use water spray to disperse vapors. Do not allow run-off from fire fighting to enter drains or water courses.

5.4. Reference to Other Sections

Refer to Section 9 for flammability properties.

SECTION 6: ACCIDENTAL RELEASE MEASURES

6.1. Personal Precautions, Protective Equipment and Emergency Procedures

General Measures: Eliminate every possible source of ignition. Do not get in eyes, on skin, or on clothing. Do not breathe gas.

6.1.1. For Non-Emergency Personnel

Protective Equipment: Use appropriate personal protective equipment (PPE).

Emergency Procedures: Evacuate unnecessary personnel.

6.1.2. For Emergency Personnel

Protective Equipment: Equip cleanup crew with proper protection.

Emergency Procedures: Eliminate ignition sources. Evacuate unnecessary personnel, isolate, and ventilate area. Upon arrival at the scene, a first responder is expected to recognize the presence of dangerous goods, protect oneself and the public, secure the area, and call for the assistance of trained personnel as soon as conditions permit.

6.2. Environmental Precautions

Prevent entry to sewers and public waters. Avoid release to the environment.

6.3. Methods and Materials for Containment and Cleaning Up

For Containment: Remove ignition sources. Stop leak, if possible without risk. As an immediate precautionary measure, isolate spill or leak area in all directions.

Methods for Cleaning Up: Clean up spills immediately and dispose of waste safely. Transfer spilled material to a suitable container for disposal. Contact competent authorities after a spill. Stop the source of the release, if safe to do so. Consider the use of water spray to disperse vapors. Isolate the area until gas has dispersed. Ventilate and gas test area before entering.

6.4. Reference to Other Sections

See Section 8 for exposure controls and personal protection and Section 13 for disposal considerations.

SECTION 7: HANDLING AND STORAGE

7.1. Precautions for Safe Handling

Additional Hazards When Processed: Handle empty containers with care because residual vapors are flammable. Ruptured cylinders may rocket. Do not pressurize, cut, or weld containers. Asphyxiating gas at high concentrations.

Precautions for Safe Handling: Wash hands and other exposed areas with mild soap and water before eating, drinking or smoking and when leaving work. Avoid prolonged contact with eyes, skin and clothing. Do not breathe gas.

Hygiene Measures: Handle in accordance with good industrial hygiene and safety procedures.

7.2. Conditions for Safe Storage, Including Any Incompatibilities

Technical Measures: Comply with applicable regulations. Proper grounding procedures to avoid static electricity should be followed.

Storage Conditions: Keep container closed when not in use. Store in a dry, cool place. Keep/Store away from direct sunlight, extremely high or low temperatures and incompatible materials. Keep in fireproof place. Cylinders should be stored upright with valve protection cap in place and firmly secured to prevent falling.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Incompatible Materials: Strong acids, strong bases, strong oxidizers.

7.3. Specific End Use(s)

Fuel

SECTION 8: EXPOSURE CONTROLS/PERSONAL PROTECTION

8.1. Control Parameters

For substances listed in section 3 that are not listed here, there are no established exposure limits from the manufacturer, supplier, importer, or the appropriate advisory agency including: ACGIH (TLV), AIHA (WEEL), NIOSH (REL), OSHA (PEL), or Canadian provincial governments.

Ethanethiol (75-08-1)		
USA ACGIH	ACGIH OEL TWA [ppm]	0.5 ppm
USA OSHA	OSHA PEL (Ceiling)	25 mg/m³
USA OSHA	OSHA PEL C [ppm]	10 ppm
USA NIOSH	NIOSH REL (Ceiling)	1.3 mg/m³
USA NIOSH	NIOSH REL C [ppm]	0.5 ppm
USA IDLH	IDLH [ppm]	500 ppm
Alberta	OEL TWA	1.3 mg/m³
Alberta	OEL TWA [ppm]	0.5 ppm
British Columbia	OEL TWA [ppm]	0.5 ppm
Manitoba	OEL TWA [ppm]	0.5 ppm
New Brunswick	OEL TWA	1.3 mg/m³
New Brunswick	OEL TWA [ppm]	0.5 ppm
Newfoundland & Labrador	OEL TWA [ppm]	0.5 ppm
Nova Scotia	OEL TWA [ppm]	0.5 ppm
Nunavut	OEL STEL [ppm]	1.5 ppm
Nunavut	OEL TWA [ppm]	0.5 ppm
Northwest Territories	OEL STEL [ppm]	1.5 ppm
Northwest Territories	OEL TWA [ppm]	0.5 ppm
Ontario	OEL TWA [ppm]	0.5 ppm
Prince Edward Island	OEL TWA [ppm]	0.5 ppm
Québec	VEMP (OEL TWA)	1.3 mg/m³
Québec	VEMP (OEL TWA) [ppm]	0.5 ppm
Saskatchewan	OEL STEL [ppm]	1.5 ppm
Saskatchewan	OEL TWA [ppm]	0.5 ppm
Yukon	OEL C	7.6 mg/m³
Yukon	OEL Ceiling [ppm]	3 ppm

8.2. Exposure Controls

Appropriate Engineering Controls: Suitable eye/body wash equipment should be available in the vicinity of any potential exposure. Ensure adequate ventilation, especially in confined areas. Ensure all national/local regulations are observed. Use explosion-proof equipment. Proper grounding procedures to avoid static electricity should be followed. Gas detectors should be used when flammable gases or vapors may be released. Oxygen detectors should be used when asphixiating gases may be released.

Personal Protective Equipment: Gloves. Protective clothing. Protective goggles. Insufficient ventilation: wear respiratory protection. Respiratory protection of the dependent type.



Materials for Protective Clothing: Chemically resistant materials and fabrics. Wear fire/flame resistant/retardant clothing.

Hand Protection: Wear protective gloves. If material is cold, wear thermally resistant protective gloves.

Eye and Face Protection: Chemical safety goggles.

Skin and Body Protection: Wear suitable protective clothing.

Respiratory Protection: Use a NIOSH-approved self-contained breathing apparatus whenever exposure may exceed established Occupational Exposure Limits.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Thermal Hazard Protection: Wear thermally resistant protective clothing.

Other Information: When using, do not eat, drink or smoke.

SECTION 9: PHYSICAL AND CHEMICAL PROPERTIES

9.1. Information on Basic Physical and Chemical Properties

Physical State	:	Gas
Appearance	:	Colorless
Odor	:	Normally odorless, Pungent odor observed if mercaptans are present.
Odor Threshold	:	No data available
pH	:	No data available
Evaporation Rate	:	No data available
Melting Point	:	No data available
Freezing Point	:	No data available
Boiling Point	:	No data available
Flash Point	:	-184 °C (-299.2 °F)
Auto-ignition Temperature	:	537 °C (998.6 °F)
Decomposition Temperature	:	No data available
Flammability (solid, gas)	:	Extremely flammable gas
Lower Flammable Limit	:	2 %
Upper Flammable Limit	:	10 %
Vapor Pressure	:	40 mm Hg (0.77 psi)
Relative Vapor Density at 20°C	:	No data available
Relative Density	:	No data available
Specific Gravity	:	No data available
Solubility	:	Water: Not miscible or difficult to mix
Partition Coefficient: N-Octanol/Water	:	No data available
Viscosity	:	No data available
Explosive Properties	:	Contains gas under pressure; may explode if heated

SECTION 10: STABILITY AND REACTIVITY

10.1. Reactivity:

Hazardous reactions will not occur under normal conditions.

10.2. Chemical Stability:

Contains gas under pressure; may explode if heated.

10.3. Possibility of Hazardous Reactions:

Hazardous polymerization will not occur.

10.4. Conditions to Avoid:

Direct sunlight, extremely high or low temperatures, open flames, sources of ignition and incompatible materials.

10.5. Incompatible Materials:

Strong acids, strong bases, strong oxidizers.

10.6. Hazardous Decomposition Products:

Thermal decomposition may produce: Hydrocarbons. Sulfur compounds.

SECTION 11: TOXICOLOGICAL INFORMATION

11.1. Information on Toxicological Effects - Product

Acute Toxicity (Oral): Not classified

Acute Toxicity (Dermal): Not classified

Acute Toxicity (Inhalation): Not classified

LD50 and LC50 Data:

No additional information available

Skin Corrosion/Irritation: Not classified

Eye Damage/Irritation: Not classified

Respiratory or Skin Sensitization: Not classified

Germ Cell Mutagenicity: Not classified

Carcinogenicity: Not classified

Specific Target Organ Toxicity (Repeated Exposure): Not classified

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Reproductive Toxicity: Not classified

Specific Target Organ Toxicity (Single Exposure): Not classified

Aspiration Hazard: Not classified

Symptoms/Injuries After Inhalation: In elevated concentrations may cause asphyxiation, central nervous system effects, and increased breathing rate. Symptoms of asphyxiation include headache, dizziness, rapid breathing, increased pulse, mood changes, tremors, cyanosis, muscular weakness, narcosis, numbness of the extremities, unconsciousness and death.

Symptoms/Injuries After Skin Contact: Contact with gas escaping the container can cause frostbite and freeze burns.

Symptoms/Injuries After Eye Contact: Contact with gas escaping the container can cause frostbite, freeze burns, and permanent eye damage.

Symptoms/Injuries After Ingestion: Not considered a potential route of exposure, but contact with gas escaping the container can cause freeze burns and frostbite.

Chronic Symptoms: None known.

Potential Adverse human health effects and symptoms: Based on available data, the classification criteria are not met.

11.2. Information on Toxicological Effects - Ingredient(s)

LD50 and LC50 Data:

Ethanethiol (75-08-1)	
LD50 Oral Rat	682 mg/kg
LD50 Dermal Rat	> 2000 mg/kg
LC50 Inhalation Rat	11.23 mg/L/4h
LC50 Inhalation Rat	4420 ppm/4h

SECTION 12: ECOLOGICAL INFORMATION

12.1. Toxicity

Ecology - General: Harmful to aquatic life with long lasting effects.

Ethanethiol (75-08-1)	
LC50 Fish 1	2.2 mg/L
EC50 - Crustacea [1]	90 – 280 mg/L (Exposure time: 48 h - Species: Daphnia magna)
EC50 - Crustacea [2]	0.09 – 0.28 mg/L (Exposure time: 48 h - Species: Daphnia magna [Static])
NOEC Chronic Crustacea	0.009 mg/L

12.2. Persistence and Degradability

Natural Gas Dry	
Persistence and Degradability	May cause long-term adverse effects in the environment.

12.3. Bioaccumulative Potential

Natural Gas Dry	
Bioaccumulative Potential	Not established.
Natural gas, dried (68410-63-9)	
Partition coefficient n-octanol/water (Log Pow)	≤ 2.8
Ethanethiol (75-08-1)	
Partition coefficient n-octanol/water (Log Pow)	1.5 (at 20 °C (at pH 7)

12.4. Mobility in Soil

No additional information available

12.5. Other Adverse Effects

Other Information: Avoid release to the environment.

SECTION 13: DISPOSAL CONSIDERATIONS

13.1. Waste treatment methods

Waste Disposal Recommendations: Dispose of contents/container in accordance with local, regional, national, territorial, provincial, and international regulations.

Additional Information: Handle empty containers with care because residual vapors are flammable. Empty gas cylinders should be returned to the vendor for recycling or refilling. Do not puncture or incinerate container.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Ecology - Waste Materials: Avoid release to the environment. This material is hazardous to the aquatic environment. Keep out of sewers and waterways.

SECTION 14: TRANSPORT INFORMATION

The shipping description(s) stated herein were prepared in accordance with certain assumptions at the time the SDS was authored, and can vary based on a number of variables that may or may not have been known at the time the SDS was issued.

14.1. In Accordance with DOT

Proper Shipping Name : COMPRESSED GAS, FLAMMABLE (natural gas-high methane content)
Hazard Class : 2.1
Identification Number : UN1954
Label Codes : 2.1
ERG Number : 115



14.2. In Accordance with IMDG

Proper Shipping Name : COMPRESSED GAS, FLAMMABLE (natural gas-high methane content)
Hazard Class : 2.1
Identification Number : UN1954
Label Codes : 2.1
EmS-No. (Fire) :F-D
EmS-No. (Spillage) : S-U



14.3. In Accordance with IATA

Proper Shipping Name : COMPRESSED GAS, FLAMMABLE (natural gas-high methane content)
Hazard Class : 2.1
Identification Number : UN1954
Label Codes : 2.1
ERG Code (IATA) : 10L



14.4. In Accordance with TDG

Proper Shipping Name : COMPRESSED GAS, FLAMMABLE (natural gas-high methane content)
Hazard Class : 2.1
Identification Number : UN1954
Label Codes : 2.1



SECTION 15: REGULATORY INFORMATION

15.1. US Federal Regulations

Natural Gas Dry	
SARA Section 311/312 Hazard Classes	Physical hazard - Flammable (gases, aerosols, liquids, or solids) Physical hazard - Gas under pressure Health hazard - Simple asphyxiant

Natural gas, dried (68410-63-9)
Listed on the United States TSCA (Toxic Substances Control Act) inventory - Status: Active

Ethanethiol (75-08-1)
Listed on the United States TSCA (Toxic Substances Control Act) inventory - Status: Active

15.2. US State Regulations

Ethanethiol (75-08-1)
U.S. - New Jersey - Right to Know Hazardous Substance List U.S. - Pennsylvania - RTK (Right to Know) List U.S. - Massachusetts - Right To Know List

15.3. Canadian Regulations

Natural gas, dried (68410-63-9)
Listed on the Canadian DSL (Domestic Substances List)

Ethanethiol (75-08-1)
Listed on the Canadian DSL (Domestic Substances List)

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

SECTION 16: OTHER INFORMATION, INCLUDING DATE OF PREPARATION OR LAST REVISION

Date of Preparation or Latest Revision : 02/22/2023

Other Information : This document has been prepared in accordance with the SDS requirements of the OSHA Hazard Communication Standard 29 CFR 1910.1200 and Canada's Hazardous Products Regulations (HPR) SOR/2015-17.

GHS Full Text Phrases:

H220	Extremely flammable gas
H224	Extremely flammable liquid and vapor
H280	Contains gas under pressure; may explode if heated
H302	Harmful if swallowed
H317	May cause an allergic skin reaction
H332	Harmful if inhaled
H400	Very toxic to aquatic life
H402	Harmful to aquatic life
H410	Very toxic to aquatic life with long lasting effects
H412	Harmful to aquatic life with long lasting effects

This information is based on our current knowledge and is intended to describe the product for the purposes of health, safety and environmental requirements only. It should not therefore be construed as guaranteeing any specific property of the product.

NA GHS SDS 2015 (Can, US)

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX E: AIR DISPERSION MODELING ANALYSIS

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Air Quality Dispersion Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

Lewis County, Washington

December 2025

Prepared for

TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, Washington 98531

Submitted to

Southwest Clean Air Agency
5101 NE 82nd Ave.
Vancouver, Washington 98662
and
Washington Dept. of Ecology
300 Desmond Drive SE
Lacey, Washington 98503

Prepared by

TETRA TECH
10 Post Office Square, 11th Floor
Boston, MA 02109

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table of Contents

1.0 INTRODUCTION 1

2.0 FACILITY DESCRIPTION AND REGULATORY APPLICABILITY 4

2.1 Site Location 4
2.2 Project Description 4
2.3 Summary of Annual Potential Emissions 4
2.4 Ambient Air Quality Regulatory Criteria 5
2.4.1 National Ambient Air Quality Standards 5
2.4.2 New Source Review 7
2.4.3 Prevention of Significant Deterioration 7
2.4.4 Toxic Air Pollution Sources Review 8

3.0 AIR QUALITY IMPACT ASSESSMENT METHODOLOGY 10

3.1 Introduction 10
3.2 Source Data and Operating Scenarios 12
3.3 Model Selection 16
3.4 Meteorological Data for AERMOD 16
3.5 Land Use 17
3.6 Good Engineering Practice Stack Height Analysis 18
3.7 Receptor Grid and AERMAP Processing 19
3.8 Ambient Background Data 20
3.9 Modeling Methodology 23
3.9.1 NO_2 Modeling Methods 24
3.10 Assessment of Secondary Particulate and Ozone 24
3.11 Toxic Air Pollutant Source Impact analysis 25

4.0 AIR QUALITY MODELING RESULTS 25

4.1 Introduction 25
4.2 Load Analysis 26
4.3 Secondary Pollutant Assessment 26
4.3.1 Secondary $PM_{2.5}$ Assessment 26
4.3.2 Ozone Ambient Impact Assessment 27
4.4 Project Impacts Compared to the SILs 28
4.5 NAAQS Analysis 28
4.6 Toxic Air Pollutant Modeling Results 29

5.0 REFERENCES 31

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

List of Tables

Table 2-1. Project Annual Potential Emissions (tons per year, tpy) 5
Table 2-2. National Ambient Air Quality Standards 5
Table 2-3. Centralia Coal to Gas Baseline Net Emissions and PSD Applicability Thresholds 7
Table 2-4. TransAlta Project De Minimis TAP Emissions 8
Table 2-5. TransAlta Project SQER TAP Emissions 9
Table 2-6. TransAlta Project TAP Emissions for Dispersion Modeling 9
Table 2-7. TransAlta Project 1998 SQER TAP Emissions 10
Table 2-8. TransAlta Project 1998 TAP Emissions for Dispersion Modeling 10
Table 3-1. SILs and NAAQS 11
Table 3-2. Physical Stack Characteristics 13
Table 3-3. Stack Exhaust Parameters and Emission Rates 14
Table 3-4. Proposed Air Quality Background Concentrations 23
Table 3-5. Margin between Ambient Air Quality Concentrations and the NAAQS 23
Table 4-1. SILs Analysis Results 28
Table 4-2. NAAQS Analysis Results 29
Table 4-3 TAPs Analysis Results 30
Table 4-4 1998 TAPs Analysis Results 30

List of Figures

Figure 1-1. Facility Location Map 3
Figure 3-1. Five-year (2020-2024) Wind Rose of Wind Measurements at Olympia Meteorological Station 17
Figure 3-2. Urban / Rural Land Use Determination within a 3 km radius 18
Figure 3-3. Full Nested Cartesian Receptor Grid including the Refined Receptor Grid 21
Figure 3-4. Zoomed to Inner Grids of the Nested Cartesian Receptor Grid 22
Figure B-1. AERMOD Predicted 1-hour NO_2 Concentration Contours 1
Figure B-2. AERMOD Predicted Annual (2020) NO_2 Concentration Contours 2
Figure B-3. AERMOD Predicted 24-Hour $PM_{2.5}$ Concentration Contours 3
Figure B-4. AERMOD Predicted Annual $PM_{2.5}$ Concentration Contours 4

List of Appendices

Appendix A: Unit #2 Load Analysis
Appendix B: Project Predicted Concentration Contours for NAAQS Analyses

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Acronyms/Abbreviations

µg/m^3	micrograms per cubic meter
ARM2	Ambient Ratio Method 2
ASIL	Acceptable Source Impact Levels
BPIP	Building Profile Input Program
CFR	Code of Federal Regulations
CO	carbon monoxide
GEP	Good Engineering Practice
GHGs	greenhouse gases
GRSM	Generic Reaction Set Method
H1H	highest first high
H2H	highest second high
H_2SO_4	sulfuric acid
H4H	highest fourth high
H6H	highest sixth high
H8H	highest eighth high
km	kilometer
lb	pound
m	meters
MMBtu/hr	million British thermal units per hour
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Data
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSR	New Source Review
O_3	ozone
OLM	Ozone Limiting Method
Pb	lead
PM_{10}	particulate matter with a diameter equal to or less than 10 microns

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
ppb	parts per billion
ppm	parts per million
The Project	Conversion of coal to natural gas firing in Unit #2 project
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
Report	Air Quality Modeling Report for the Project (this document)
SER	Significant Emission Rate
SIL	Significant Impact Level
SO_2	sulfur dioxide
SQER	small quantity emission rates
TAP	toxic air pollutant
tBACT	toxics Best Available Control Technology
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WDOE	Washington Department of Ecology

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility, which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be passed through or bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas-starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the annual emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application which requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. The proposed methodology for the air quality dispersion modeling analyses was submitted to the Washington Department of Ecology (WDOE) and the Southwest Clean Air Agency (SWCAA) in a Modeling Protocol. WDOE (in the role of designated model reviewer) reviewed and approved the proposed approach on 10/13/2025. This document is the air quality dispersion modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project's location and expected emissions, along with an applicability assessment relative to key regulations related to the air quality impact analysis. Section 3 presents a detailed description of the modeling approach proposed for evaluating air quality impacts of the proposed Project including: source data and operating scenarios, model selection criteria, an urban/rural land use determination, Good Engineering Practice (GEP) stack height determination and building dimensions for model input, meteorological data, the receptor grids, ambient monitored background concentrations, as well as assessments for secondary ozone (O_3) and particulate matter with diameters of less than 2.5 micrometers ($PM_{2.5}$). The air quality modeling results demonstrating compliance are presented in Section 4. References cited in the document are presented in Section 5. Electronic modeling files are being submitted to the agencies with this Report. To facilitate the review of this Report and modeling files, the individual familiar with the dispersion modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Modeling Consultant: Liz Hendrick, CCM
Tetra Tech, Inc.
10 Post Office Square, 11th Floor
Boston, MA 02109
Telephone: (978) 303-8524
Email: Liz.Hendrick@tetratech.com

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

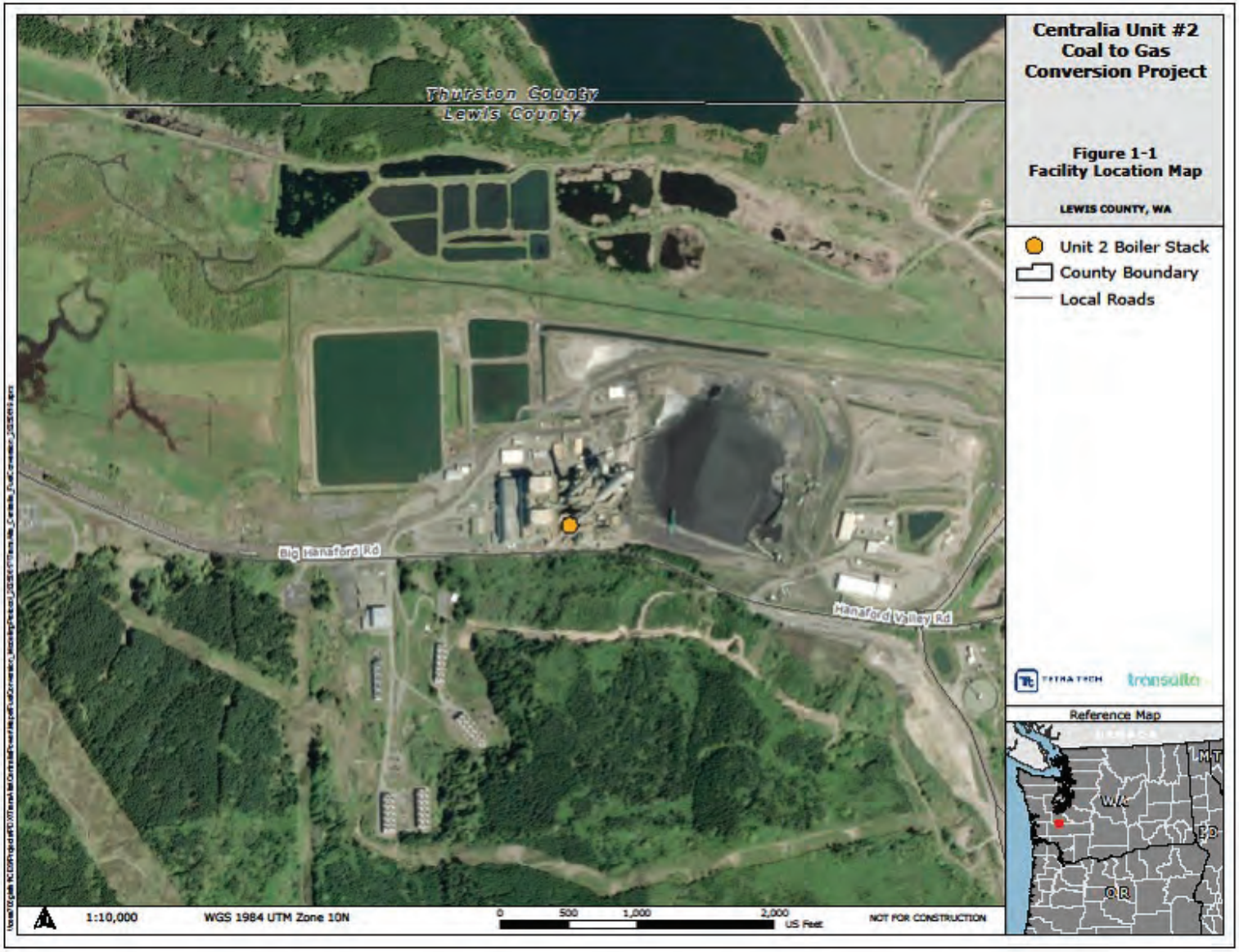


Figure 1-1. Facility Location Map

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.0 FACILITY DESCRIPTION AND REGULATORY APPLICABILITY

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The Project is surrounded by two fences to restrict public access to the generation area and the cooling tower area. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land.

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to be used to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The Project will be fully contracted to Puget Sound Energy (the Customer), and the Customer will be responsible for procuring and delivering all fuel to the converted facility and will also control dispatch of the facility. The Project is not designed nor intended to operate continuously or at a high capacity or baseload factor. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. In any event, the facility will not operate for more than 59 percent of all hours on an annual basis over the life of the Project. TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

Given the marginal cost of the unit, it is expected only during periods of high demand and reliability need, with the majority of operating hours expected at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project will include the replacement of the existing auxiliary boiler (currently diesel-fired, will be solely natural gas-fired), two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The natural gas will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boilers via a short 1,300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-1. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied,

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

as necessary. Potential emission rates for Unit #2 are based upon full load operation for 5,168 hours per year (i.e., 59% capacity factor) combusting natural gas. Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year.

Table 2-1. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[c, b]	Water Bath Heaters (2)[d, b]	Cooling Towers (2)	Project Wide Totals[e]
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.
[e] The emissions listed are slightly different than those provided in the application due to rounding.

2.4 Ambient Air Quality Regulatory Criteria

The USEPA has promulgated regulations that establish National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments. The NAAQS are established in 40 Code of Federal Regulations (CFR) 50 and incorporated in the Washington air pollution regulations. The PSD regulations are established in 40 CFR 52 and incorporated in Washington's air pollution control regulations. These regulations and guidelines provide the basis for an evaluation of the potential impacts of the proposed Project on air quality.

2.4.1 National Ambient Air Quality Standards

The USEPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are sulfur dioxide (SO_2), particulate matter with diameters of less than 10 micrometers (PM_{10}), $PM_{2.5}$, nitrogen dioxide (NO_2), carbon monoxide (CO), O_3, and lead (Pb). The NAAQS have been developed for short-term periods of 24 hours or less and annual averages. The NAAQS include both "primary" and "secondary" standards, where the primary standards are set to protect human health, allowing an adequate margin of safety. Secondary standards are set to protect public welfare from any known or anticipated adverse effects associated with the presence of air pollutants in the ambient air. The current NAAQS are provided in Table 2-2.

Table 2-2. National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS (µg/m³) [a]	
		Primary	Secondary
NO_2	Annual[b]	100	Same

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Pollutant	Averaging Period	NAAQS (µg/m³) [a]	
		Primary	Secondary
	1-hour[c]	188	None
SO_2	Annual[b,d]	80	26.2
	1-hour[e]	196	None
CO	8-hour[f]	10,000	None
	1-hour[f]	40,000	None
PM_{10}	24-hour[g]	150	Same
$PM_{2.5}$	Annual[h]	9	15
	24-hour[i]	35	Same
O_3	8-hour[j]	0.070 ppm[k]	Same
Pb	3-month[b]	0.15	Same

[a] µg/m³ = micrograms per cubic meter
[b] Not to be exceeded.
[c] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average must not exceed 100 parts per billion (ppb) (188 µg/m³).
[d] The annual average secondary standard for SO_2 is based on the annual mean averaged over 3 years and must not exceed 10 ppb.
[e] To attain this standard, the 3-year average of 99th percentile of the daily maximum 1-hour average must not exceed 75 ppb (196 µg/m³).
[f] Not to be exceeded more than once per year.
[g] Not to be exceeded more than once per year on average over 3 years.
[h] To attain this standard, the 3-year average of weighted annual mean $PM_{2.5}$ concentrations must not exceed 9 µg/m³.
[i] To attain this standard, the 3-year average of 98th percentile of 24-hour concentrations must not exceed 35 µg/m³.
[j] To attain this standard, the 3-year average of the fourth highest daily maximum 8-hour average O_3 concentrations averaged over 3 years must not exceed 0.070 ppm.
[k] ppm = parts per million

One of the primary goals of federal and state air pollution regulations is to ensure that ambient air quality is in compliance with the NAAQS. Toward this end, every area of the United States has been designated as “attainment”, “unclassifiable” or “nonattainment” for each criteria pollutant. In areas designated as attainment, the air quality with respect to the pollutant is equal to or better than the NAAQS. These areas are under a mandate to maintain, i.e., prevent significant deterioration of such air quality. In areas designated as unclassifiable, there is limited air quality data, and these areas are treated as attainment areas for regulatory purposes. In areas designated as nonattainment for a particular pollutant, the air quality with respect to that pollutant is worse than the NAAQS. These areas must take actions to improve air quality and attain compliance with the NAAQS within a certain period of time.

If a new major source of air pollution is proposed, it must undergo New Source Review (NSR) air permitting. The NSR air permitting regulations contain two distinct programs, one for sources proposed in attainment/unclassifiable areas and one for sources in nonattainment areas. The NSR program for sources proposed in attainment/unclassifiable areas is known as the PSD program. The NSR program for sources proposed in non-attainment areas is known as nonattainment new source review (NNSR).

The Facility location in Lewis County, Washington state is presently classified as attainment/unclassifiable for all criteria pollutants. Thus, emissions of criteria pollutants from the Project are evaluated with respect to the PSD program. The requirements of the NSR program are discussed in more detail in the following subsections.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.4.2 New Source Review

NSR applies to new major sources of air pollutants and major modifications of existing major sources. The NSR program includes two distinct permitting programs, PSD permitting for projects located in areas designated as unclassified or attainment with the NAAQS, and NNSR permitting for projects located in areas designated as nonattainment with the NAAQS. As an area may be in attainment with one or more NAAQS, but in nonattainment with one or more other NAAQS at the same time, an individual project may be subject to both PSD and NNSR permitting, depending upon its potential emissions on a pollutant-by-pollutant basis. The federal PSD program under 40 CFR 52.21 applies to subject sources in the U.S. and the program is administered by the USEPA.

2.4.3 Prevention of Significant Deterioration

The Project is located at the TransAlta Centralia Generating facility which is currently an existing major source for emissions of nitrogen oxides (NO_X), CO, SO_2, particulate matter (PM), PM_{10}, $PM_{2.5}$, volatile organic compounds (VOCs), sulfuric acid (H_2SO_4), and greenhouse gases (GHGs). Accordingly, the Project is considered a modification of the existing Centralia facility and is subject to PSD permitting if it meets the definition of a major modification under this permitting program. This analysis focused on Unit #2, evaluating the proposed overall project emissions with respect to the Unit #2 baseline emissions, and using 2022-2023 as the baseline period. The modification results in a net decrease in emissions from Unit #2 at the existing generating facility (except for VOC). Table 2-3 provides a comparison of the Project's potential emissions to the PSD Significant Emission Rates (SER). VOC is the only pollutant that exceeds the SER. As such, the Project will not result in a significant emissions increase (i.e. greater than the respective SER) for all criteria pollutants and does not trigger a PSD modeling analysis. An air dispersion modeling analysis was conducted in accordance with USEPA guidance as described in the Modeling Protocol. Modeling was conducted for Facility emissions of CO, NO_X, PM_{10}, $PM_{2.5}$ and SO_2 because NAAQS for these pollutants have been established. VOC is not modeled, as there is no NAAQS for that pollutant. However, because VOC is a precursor to the formation of photochemical oxidants, O_3 impacts are assessed (as described in Section 3.10).

Table 2-3. Centralia Coal to Gas Baseline Net Emissions and PSD Applicability Thresholds

Pollutant	Unit #2[a] tpy	Auxiliary Boiler[b] tpy	Water Bath Heaters (2)[c] tpy	Cooling Towers (2) tpy	Project Wide Totals tpy	PSD Significant Emission Rate tpy
NO_X	-	1.5	1.3	-	2.8	40
CO	-	3.6	3.2	-	6.8	100
VOC	57.9	0.5	0.4	-	58.8	40
PM_{10}	-	0.7	0.6	3.0	4.3	15
$PM_{2.5}$	-	0.7	0.6	1.8	3.1	10
SO_2	-	0.07	0.06	-	0.1	40
Pb	-	4E-05	4E-05	-	8E-05	0.6

[a] Based on Unit #2 operation at full load (100% load).
[b] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[c] Based on 8,760 hours of operation for two Water Bath Heaters.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.4.4 Toxic Air Pollution Sources Review

The permitting authority on the air discharge permit (ADP) application, SWCAA, requires a review of new or modified toxic air pollution sources as part of that application, per SWCAA 400-076 and Washington Administrative Code (WAC) Chapter 173-460. The air toxics program uses a tiered review approach for regulating toxic air pollutant (TAP) emissions increases that are greater than de minimis levels. The regulations under WAC 173-460-060 also require the use of the "toxics Best Available Control Technology" (tBACT) for emission control on new or modified sources where emissions exceed de minimis thresholds. The first-tier review, outlined in WAC 173-460-080, involves evaluating the aggregate potential emissions increase of each TAP in an acceptable source impact analysis. The acceptable source impact analysis involves either comparing the increase in emissions against established small quantity emission rates (SQER) or comparing the increase in impact at any location outside of property boundaries against the Acceptable Source Impact Levels (ASILs). The current de minimis, SQER, and ASIL limits are listed in WAC 173-460-150. SWCAA additionally requires an acceptable source impact analysis to be conducted for first tier review based on the 1998 version of the WAC 173-460-080 air toxic rules. The 1998 rules have different SQER and ASIL values and do not have de minimis levels. In some cases, the 1998 rules regulate different TAPs than the current regulation. To show TAP emissions are below ASILs, dispersion modeling is required.

The first-tier review determines if the TAP source meets health-based standards without requiring additional review. If the TAP is below either the SQER or the ASIL threshold, that TAP shows an acceptable source impact and has passed the first-tier review. If compliance cannot be demonstrated in this first tier, the source may be subject to a second-tier review, which involves more detailed analysis and possibly stricter controls. A third-tier review may be conducted if further evaluation is needed.

The Project's cumulative potential increase in TAP emissions from the new and modified sources were quantified and compared to the limits in the current and the 1998 version of the WAC 173-460-080 air toxic rules. It should be noted that TAP emissions reductions from past baseline operations for Unit #2 combusting coal were taken into account for NO_2, CO, SO_2, and H_2SO_4.[1] Cumulative emissions from these four TAPs will decrease as a result of the Project. Therefore, they are not included in the acceptable source impact analysis. Aside from these four TAPs, pollutant reductions from the Unit #2 baseline were not considered and the acceptable source impact analysis is expected to be a conservative proposal for certain TAPs.

2.4.4.1 Toxic Air Pollutants to Model Based on Current Air Toxic Rules

The first-tier review of TAPs based on the current WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to de minimis thresholds. Table 2-4 shows Project TAPs that are below their respective de minimis limits. The remaining significant TAPs were then compared to the SQER thresholds. Table 2-5 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-6 lists the project's TAP emissions that exceed SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-4. TransAlta Project De Minimis TAP Emissions

[1] The Unit #2 emissions reductions from baseline are discussed at length in the ADP application narrative with respect to PSD applicability.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	De Minimis Threshold	Proposed Emissions Less than De Minimis?
Chrysene	218-01-9	lb/year	6.4E-02	4.5E-01	Yes
Toluene	108-88-3	lb/24-hr	5.7E-01	1.9E+01	Yes
Copper	7440-50-8	lb/1-hr	5.9E-03	9.3E-03	Yes
Selenium	7782-49-2	lb/24-hr	4.0E-03	7.4E-02	Yes

Table 2-5. TransAlta Project SQER TAP Emissions

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	SQER Threshold	Proposed Emissions Less than SQER?
Benz(a)anthracene	56-55-3	lb/year	6.4E-02	8.9E-01	Yes
Benzo(a)pyrene	50-32-8	lb/year	4.2E-02	1.6E-01	Yes
Benzo(b)fluoranthene	205-99-2	lb/year	6.4E-02	8.9E-01	Yes
Benzo(k)fluoranthene	207-08-9	lb/year	6.4E-02	8.9E-01	Yes
Dibenzo(a,h)anthracene	53-70-3	lb/year	4.2E-02	4.1E-03	Yes
Indo(1,2,3-cd)pyrene	193-39-5	lb/year	6.4E-02	8.9E-01	Yes
Chromium III	7440-47-3	lb/24-hr	1.9E-01	3.7E-01	Yes

Table 2-6. TransAlta Project TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m³)
3-Methylcholanthrene	56-49-5	lb/year	6.4E-02	9.6E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	lb/year	5.7E-01	8.5E-06
Benzene	71-43-2	lb/year	1.0E+02	1.3E-01
Dichlorobenzene	106-46-7	lb/year	4.2E+01	9.1E-02
Formaldehyde	50-00-0	lb/year	8.1E+03	1.7E-01
n-Hexane	110-54-3	lb/24-hr	3.0E+02	7.0E+02
Naphthalene	91-20-3	lb/year	1.8E+02	2.9E-02
Silica	7631-86-9	lb/24-hr	4.2E+00	3.0E+00
Arsenic	7440-38-2	lb/year	8.2E+01	3.0E-04
Beryllium	7440-41-7	lb/year	5.9E+01	4.2E-04
Cadmium	7440-43-9	lb/year	7.9E+01	2.4E-04
Chromium VI	18540-29-9	lb/year	1.5E+01	4.0E-06
Cobalt	7440-48-4	lb/24-hr	1.4E-02	1.0E-01
Lead	7439-92-1	lb/year	1.9E+02	8.3E-02
Manganese	7439-96-5	lb/24-hr	5.8E-01	3.0E-01
Mercury	7439-97-6	lb/24-hr	3.0E-01	3.0E-02
Nickel	7440-02-0	lb/year	9.6E+01	3.8E-03
Vanadium	7440-62-2	lb/24-hr	3.8E-01	1.0E-01

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.4.4.2 Toxic Air Pollutants to Model Based on 1998 Air Toxic Rules

The first-tier review of TAPs based on the 1998 version of the WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to SQER thresholds. Table 2-7 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-8 lists the project's TAP emissions that exceed 1998 SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-7. TransAlta Project 1998 SQER TAP Emissions

Toxic Air Pollutant	CAS #	Project Potential Emissions Totals (lb/hr)	Project Potential Emissions Totals (lb/yr)	SQER Threshold (lb/hr)	SQER Threshold (lb/yr)	Proposed Emissions Less than SQER?
Naphthalene	91-20-3	4.2E-03	22	2.6	22,750	Yes
Toluene	108-88-3	2.4E-02	120	5.0	42,748	Yes
Chromium III	7440-47-3	8.0E-03	41	0.02	175	Yes
Cobalt	7440-48-4	5.8E-04	3	0.02	175	Yes
Copper	7440-50-8	5.9E-03	30	0.02	175	Yes
Lead	7439-92-1	3.5E-03	18	-	50	Yes
Manganese	7439-96-5	2.6E-03	13	0.02	175	Yes
Mercury	7439-97-6	1.8E-03	9	0.02	175	Yes
Selenium	7782-49-2	1.7E-04	1	0.02	175	Yes
Vanadium	7440-62-2	1.6E-02	81	0.02	175	Yes

Table 2-8. TransAlta Project 1998 TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m³)
Benzene	71-43-2	lb/year	7.4E+01	1.2E-01
Formaldehyde	50-00-0	lb/year	2.7E+03	7.7E-02
n-Hexane	110-54-3	lb/24-hr	3.0E+02	2.0E+02
Arsenic	7440-38-2	lb/year	7.1E+00	9.6E-05
Beryllium	7440-41-7	lb/year	4.2E-01	8.5E-06
Cadmium	7440-43-9	lb/year	3.9E+01	1.3E-01
Chromium VI	18540-29-9	lb/year	8.9E+00	9.1E-02
Nickel	7440-02-0	lb/year	7.4E+01	1.7E-01
PAH as benzo(a)pyrene	50-32-8	lb/year	7.3E-02	7.0E+02

3.0 AIR QUALITY IMPACT ASSESSMENT METHODOLOGY

3.1 Introduction

The dispersion modeling analyses for the Project was conducted in accordance with the USEPA's *Guideline on Air Quality Models* (USEPA 2024a), as supplemented by additional agency guidance. The modeling methodology was described in an *Air Quality Dispersion Modeling Protocol* (Tetra Tech, 2025), which was submitted to and approved by WDOE (WDOE also provided support with respect to

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

the SWCAA-relevant components, the air toxics and the non-PSD pollutants). It should be noted that the Project has changed to only natural gas firing in Unit #2 and therefore the Project emissions have been updated accordingly.

As described in Section 2.4.3, the Project triggers a PSD major modification for VOC, due to the significant net emissions of that pollutant. CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2 are not subject to PSD review because the Project emissions did not exceed the PSD SERs for those pollutants, and therefore, these pollutants are not subject to the specific PSD modeling requirements. As a result, dispersion modeling was conducted for CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2, to demonstrate compliance with the NAAQS as required under SWCAA 400-110(3)(c). As there is no NAAQS for VOC, this pollutant was not subject to dispersion modeling requirements, however it is considered in the NAAQS demonstration for secondary O_3.

The dispersion modeling for the Project evaluated worst-case operating conditions associated with a 59% capacity factor at full load to predict the appropriate maximum ground-level concentration for each pollutant and averaging period. The appropriate maximum concentrations from the worst-case scenarios are compared to the significant impact levels (SILs). If the maximum concentration is below the corresponding SILs, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a cumulative impact analysis was conducted with ambient background concentrations that include other major emission sources in the area. The modeled impacts are added to ambient monitored background concentrations and the sum compared to the NAAQS. Table 3-1 provides the SILs and NAAQS, as well as the modeling rank basis, as defined by USEPA, used for the assessment of compliance with the various criteria.

Table 3-1. SILs and NAAQS

Pollutant	Averaging Period	Rank for SIL Assessment	SIL (µg/m³)	Rank for NAAQS Assessment	NAAQS (µg/m³)
NO_2	1-hour	H1H [a] (5-year average)	7.5	H8H [b] (5-year average)	188
	Annual	H1H	1	H1H	100
CO	1-hour	H1H	2,000	H2H [c]	40,000
	8-hour	H1H	500	H2H	10,000
PM_{10}	24-hour	H1H	5	H6H [d] over 5 years	150
$PM_{2.5}$	24-hour	H1H (5-year average)	1.2 [e]	H8H (5-year average)	35
	Annual	H1H (5-year average)	0.13 [e]	H1H (5-year average)	9
SO_2	1-hour	H1H	7.8	H4H (5-year average)	196
	Annual	H1H	1	H1H (5-year average)	26.2

[a] Highest first-high concentration
[b] Highest eighth-high concentration
[c] Highest second-high concentration
[d] Highest sixth-high concentration
[e] Use of SILs can be justified using ambient monitoring data, see text below.

The $PM_{2.5}$ SILs at 40 CFR 52.21(k)(2) and 40 CFR 51.165(k)(2) were vacated and remanded by the January 22, 2013 United States Court of Appeals for the District of Columbia Circuit Decision on a Sierra Club v. USEPA case. The $PM_{2.5}$ SILs that were vacated and remanded concerned portions of the

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

$PM_{2.5}$ SIL regulations that automatically exempted sources from further analyses for demonstration of compliance with NAAQS and PSD increments if the predicted $PM_{2.5}$ impacts were less than the $PM_{2.5}$ SILs. The January 22, 2013 Decision specifically did not vacate the $PM_{2.5}$ SILs at 40 CFR 165(b)(2), which provides that a major source or major modification will be considered to cause or contribute to a violation of the NAAQS when such source or modification is predicted to exceed the SIL at any locality that does not or would not meet the applicable NAAQS. Under USEPA modeling guidance issued subsequent to this January 22, 2013 Decision, $PM_{2.5}$ SILs may still be used to justify permitting decisions for $PM_{2.5}$ NAAQS and increment compliance if appropriate justification is provided that the use of such SILs is protective of NAAQS and increment compliance. For NAAQS demonstrations, a key portion of this justification typically would include demonstrating that a large margin exists between the ambient background and the standard. As shown in Section 3.8 of this Protocol, existing ambient monitoring data representative of ambient background for the Project site and surrounding area indicate that there is a substantial margin between the ambient background levels and the NAAQS (see Table 3-6). Therefore, predicted Project impacts below the respective SILs will allow for adequate protection of the NAAQS, leaving considerable margin for contributions from other interacting sources.

3.2 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year) and will be limited to that 59% capacity;
- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) water bath heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

Table 3-2 summarizes the physical stack characteristics modeled for the NAAQS analysis. Detailed emissions and source parameter data are provided in Table 3-3. The Unit #2 boiler was modeled at full load (100% load or 723 MW) and minimum stable load (190 MW) to determine which scenario resulted in the worst-case predicted impacts[2]. Then the worst-case Unit #2 scenario was modeled in combination with the auxiliary boiler, dew point heaters and cooling towers to determine total Project impacts for the NAAQS modeling analysis. The conversion of NO_X emission rates to modeled NO_2 concentrations employed the Tier 2 Ambient Ratio Method (ARM2) NO_X to NO_2 conversion assumptions.

[2] Startup and shutdown impacts were evaluated and studied for Unit #2. Based on those evaluations, combustion emissions are anticipated to be consistent across a lb/MMBtu basis, as in when the amount of fuel combusted decreases, the emissions associated with fuel combustion would also decrease. Therefore, the VOC emissions expressed in lb/MMBtu account for the startup and shutdown emissions without further need for clarification or allowances. The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 3-2. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
U2_100	Unit #2 Boiler (100% load)	510831.55	5177972.72	68.12	140.21	7.32
U2_190MW	Unit #2 Boiler (190 MW)	510831.55	5177972.72	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	510761.14	5178008.60	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	510404.72	5177875.40	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	510405.42	5177866.41	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	510533.56	5177641.83	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	510534.41	5177654.90	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	510534.92	5177668.14	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	510535.60	5177680.53	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	510536.28	5177695.13	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	510537.13	5177708.37	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	510544.53	5177640.47	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	510544.87	5177653.54	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	510545.38	5177666.78	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	510546.06	5177679.17	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	510546.74	5177693.77	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	510547.59	5177707.01	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	510638.31	5177504.10	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	510629.05	5177513.44	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	510619.50	5177523.28	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	510610.29	5177533.36	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	510600.63	5177543.17	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	510591.37	5177552.48	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	510630.64	5177496.41	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	510621.64	5177506.20	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	510612.30	5177515.69	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	510602.94	5177525.64	93.96	19.91	7.62

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
COOLT2_K	Cooling Tower 2 Cell K	510593.39	5177535.37	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	510584.10	5177544.87	93.96	19.91	7.62

[a] UTM Zone 10, WGS-84 datum

Table 3-3. Stack Exhaust Parameters and Emission Rates

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
U2_100	441.48	29.77	141.747	103.948	61.331	6.488	3.828	6.488	3.828	0.679	0.400
U2_190MW	388.71	9.55	47.797	35.051	35.052	2.188	2.188	2.188	2.188	0.229	0.229
AUXBLR	422.04	11.73	0.695	0.282	0.042	0.129	0.019	0.129	0.019	0.013	0.002
DPH_1	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
DPH_2	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
COOLT1_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
COOLT2_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

[a] UTM Zone 10, WGS-84 datum.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3.3 Model Selection

The USEPA-recommended AERMOD modeling system (USEPA 2024b) was used to conduct the dispersion modeling. The current versions of the model (AERMOD version 24142, AERMET version 24142 and AERMAP version 24142) were used to model criteria and toxic pollutants.

3.4 Meteorological Data for AERMOD

AERMOD was run in refined mode with five years (2020-2024) of hourly surface meteorological data collected at the Olympia Regional Airport meteorological station in Thurston, Washington, along with corresponding upper air data collected at McNary Field Airport in Salem, Oregon. These data were processed using the AERMET program (v24142) along with the associated programs AERMINUTE (v15272) and AERSURFACE (v20060). AERSURFACE was run based on land use data around the meteorological data collection site (Olympia Regional Airport) and considered 12 equal 30-degree sectors. The following seasonal variations were assigned:

- Winter (no snow): December, January, and February
- Transitional Spring: March, April, and May
- Midsummer: June, July, and August
- Autumn: September, October, and November

The monthly moisture conditions (average, wet, or dry) were determined for each year based on precipitation data measured in Centralia, Washington with missing data filled in from Olympia, Washington. The moisture conditions for each month were input to AERSURFACE to determine surface characteristics and results were input to AERMET for meteorological data processing. Default settings were used for the AERMET processing including the adjustment of truncated 1-minute ASOS winds. A minimum wind speed threshold of 0.5 m/s and the friction velocity adjustment (adj_u*) option were used.

A joint frequency distribution of the winds (wind rose) for the five years of meteorological data used in the AERMOD modeling analysis is presented in Figure 3-1. The predominant winds are also the strongest winds and they are from the south through southwest sector.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

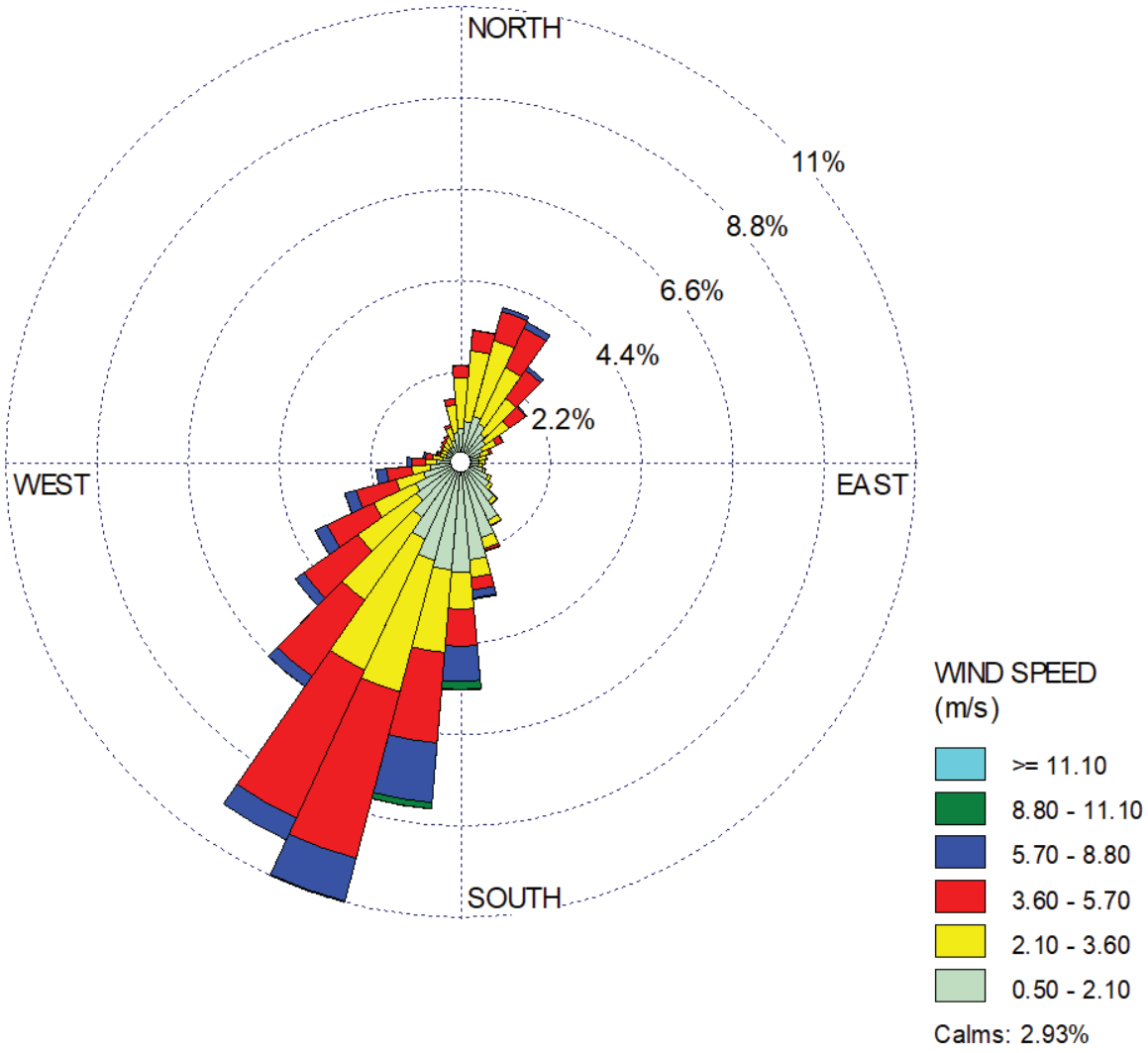


Figure 3-1. Five-year (2020-2024) Wind Rose of Wind Measurements at Olympia Meteorological Station

3.5 Land Use

It is necessary to determine whether the land-use pattern in the environs of a Project is urban or rural for modeling purposes. A land use determination has been made following the classification technique suggested by Auer (1978) in accordance with USEPA modeling guidance. The classification determination was conducted by assessing land-use categories within a 3-kilometer (km) radius of the proposed site. Figure 3-2 provides a section of an aerial photograph with the 3-km radius around the Project Site shown. Inspection of aerial photography indicates that the majority of the area is rural, with urban land uses (i.e., industrial, commercial, and dense residential) comprising less than 50% of the area within a 3 km radius. Therefore, rural dispersion coefficients were used for the air quality modeling analysis.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

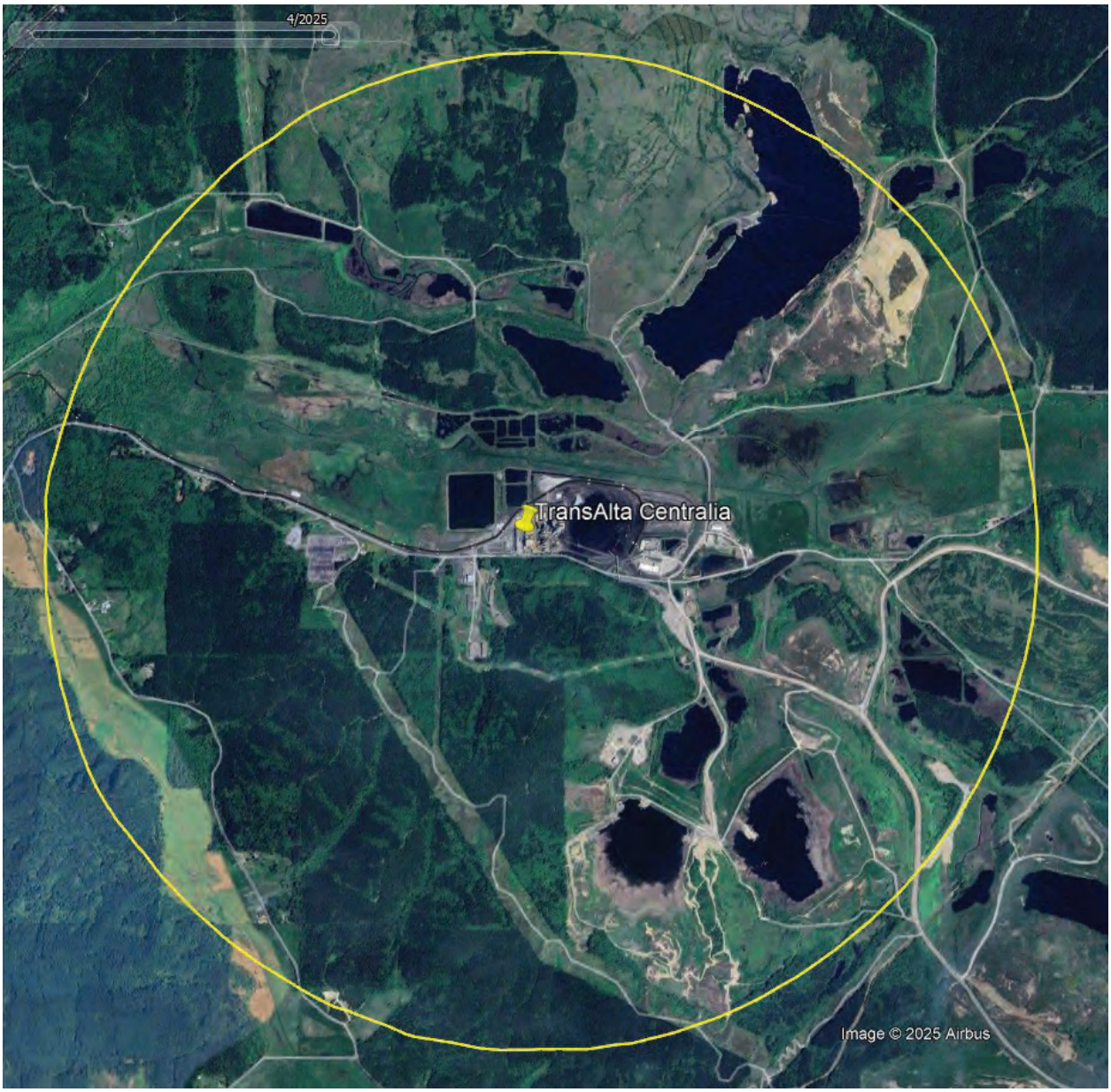


Figure 3-2. Urban / Rural Land Use Determination within a 3 km radius

3.6 Good Engineering Practice Stack Height Analysis

A GEP stack height analysis was performed based on the Project and Facility structures to determine the potential for building-induced aerodynamic downwash for the stacks. The analysis procedures described in USEPA's Guidelines for Determination of Good Engineering Practice Stack Height (USEPA 1985) guidance and included in SWCAA 400-200 Creditable Stack Height regulations were used.

The "GEP stack height" is defined as the greater of 65 meters or the formula height. The "formula height" is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground-level concentrations at a closer proximity than would

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided.

The GEP formula stack height, as defined in the 1985 final regulation, is calculated as follows:

$$H_{GEP} = H_{BLDG} + 1.5L$$

Where:

- H_{GEP} is the calculated GEP formula height;
- H_{BLDG} is the height of the nearby structure; and
- L is the lesser dimension (height or projected width) of the nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto the plane perpendicular to the direction of the wind. The GEP stack height is based on the plane projection of any structure that results in the greatest calculated height. For the purpose of the GEP analysis, nearby refers to the "sphere of influence" defined as 5 times L (the lesser dimension – height or projected width – of the nearby structure), downwind from the trailing edge of the structure.

The USEPA's Building Profile Input Program (BPIP-Prime, v04274) that is appropriate for use with the PRIME algorithms in AERMOD was used. The building dimensions and coordinates for each potentially influencing structure was input to BPIP-Prime to determine direction-specific building dimension data for input to AERMOD.

If the stack heights are below their calculated GEP height, the exhaust emissions will experience the aerodynamic effects of downwash. As determined by BPIP-Prime, all of the stack heights are below their calculated GEP height. For each stack, the controlling structures differ by direction, and wind-direction specific building dimensions are generated by BPIP-Prime for input to AERMOD. AERMOD accounts for potential downwash from nearby structures in the dispersion calculations. The PRIME algorithms in AERMOD calculate the dimensions of the structure's wake, from the cavity immediately downwind of the structure to the far wake.

3.7 Receptor Grid and AERMAP Processing

Discrete receptors were placed at 12.5-meter intervals along the Facility fence lines. There will be two fences, one surrounding the generation area of the plant and one surrounding the cooling towers across the road from the generation area. The WDOE recommended[3] a nested receptor grid with spacing as follows:

- At 12.5-meter intervals to 150 meters;
- At 25-meter intervals from 150 meters to 400 meters;
- At 50-meter intervals from 400 meters to 900 meters;
- At 100-meter intervals from 900 meters to 2,000 meters;
- At 300-meter intervals from 2,000 meters to 4,500 meters; and

[3] Email communication from Beth Friedman (WDOE) to Liz Hendrick (Tetra Tech) on 3/4/2025.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

- At 600-meter intervals from 4,500 meters to 10,000 meters.

The spacing recommendations were followed; however, because the Project involves multiple emission sources at different locations, the nested grid was extended to at least 150 meters beyond the bounding box of the sources. Per Section 9.2.2 of 40 CFR Part 51, higher-resolution receptor grids (50m spacing) will be used at predicted maxima located within coarser grid areas. Figure 3-3 shows the full nested Cartesian receptor grid including a refined grid that was used for annual NO_2 and toxics modeling. A zoomed-in view of the inner grids is provided in Figure 3-4.

Terrain elevations at receptors were obtained using Lake Environmental's AERMOD View program and United States Geological Survey (USGS) digital terrain data. AERMOD View implements the AERMAP model, which includes processing routines that extract National Elevation Data (NED) at 10-meter spacing based on North American Datum of 1983 (NAD83). The four nearest data points surrounding each receptor are used to determine receptor terrain elevations (by interpolation) for air quality model input. At WDOE's request, each receptor was assigned a flagpole height of 1.5 meters above the ground.

3.8 Ambient Background Data

Based on the recommendation of Washington WDOE, model and monitoring data from July 2014 through June 2017 were used to estimate background concentrations of criteria air pollutant design values for use in air permit analysis. The tool located at Background Concentrations 2014 - 2017 facilitates the retrieval and exploration of the estimated design values at user-specified locations in Washington, Idaho, and Oregon. These values are assumed to be inclusive of the emissions from constantly emitting surrounding sources including the coal-fired emissions from TransAlta Centralia. This results in a conservative estimate of ambient background because coal-firing at TransAlta Centralia will cease in December 2025. Significant wildfire smoke and windblown dust events have mostly been filtered out. In general, WDOE recommends using the highest value at the grid cell close to your project site as representative background concentrations. The grid cell across the road from the TransAlta Centralia Station (latitude 46.75 °N, Longitude 122.85 °W) was used. The selected representative ambient air quality background concentrations are summarized in Table 3-4.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

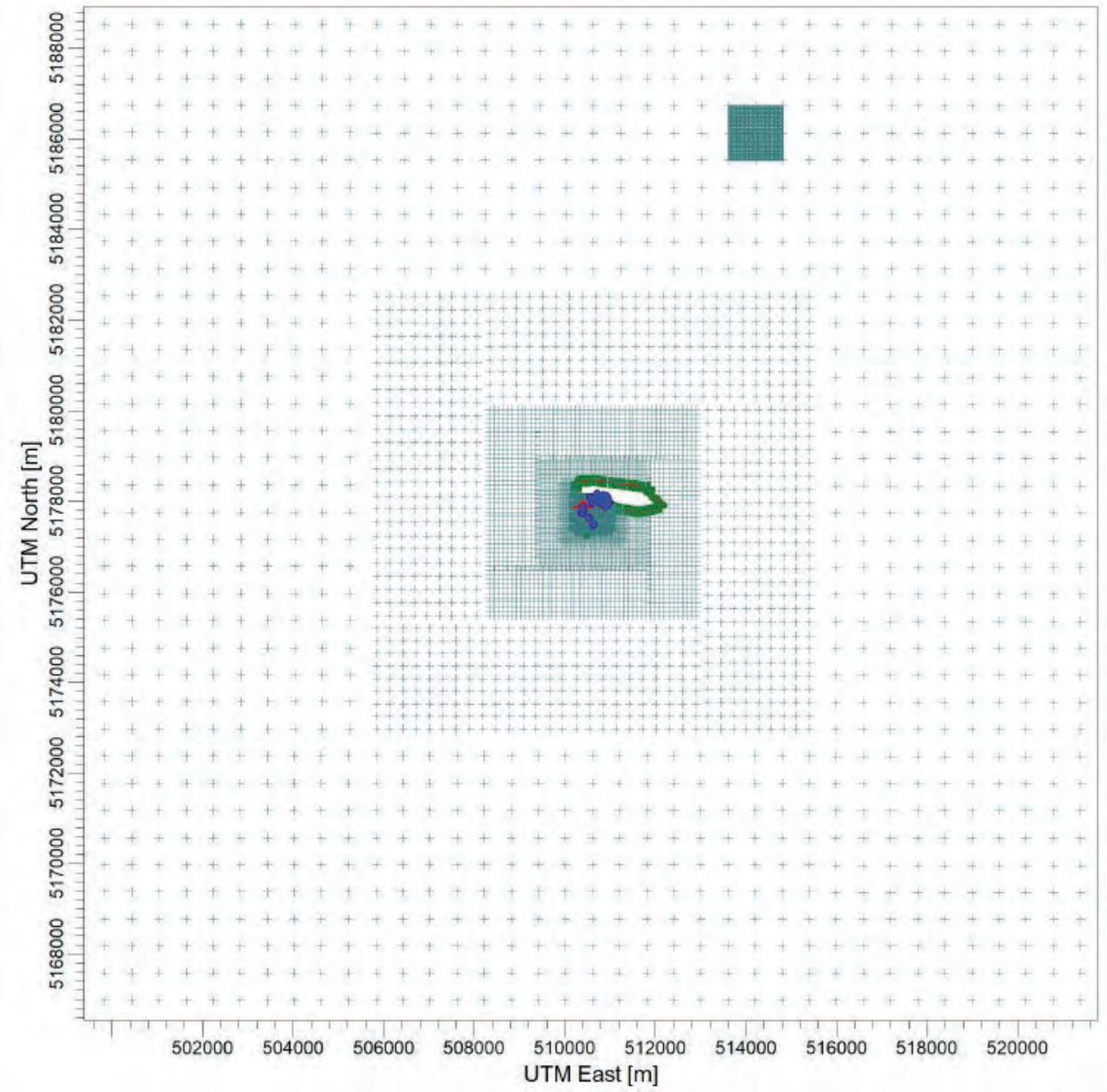


Figure 3-3. Full Nested Cartesian Receptor Grid including the Refined Receptor Grid

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

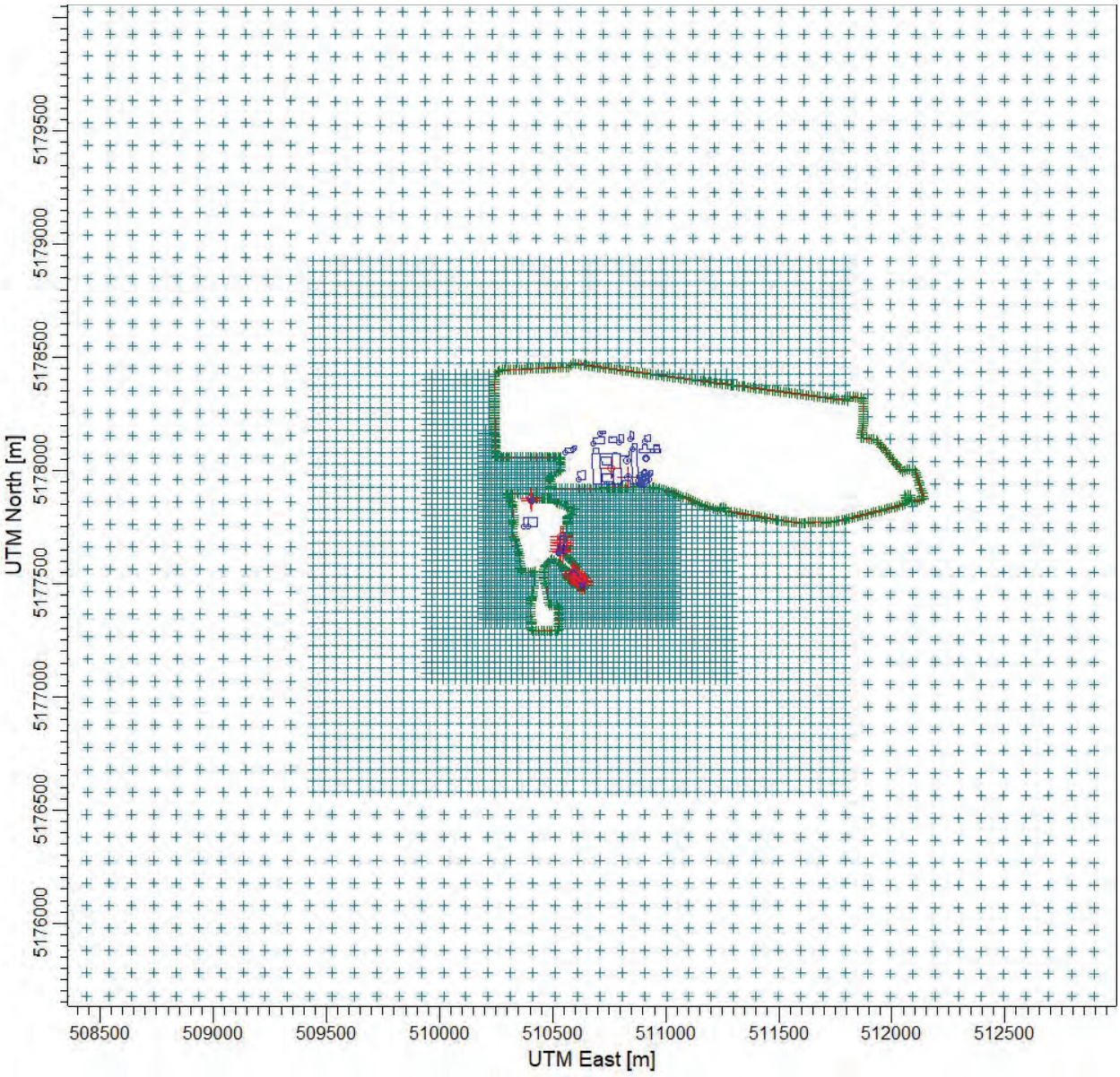


Figure 3-4. Zoomed to Inner Grids of the Nested Cartesian Receptor Grid

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 3-4. Proposed Air Quality Background Concentrations

Pollutant	Averaging Period	Grid Cell[a]	Background Conc.		
			ppm	ppb	µg/m³
CO	1-hour	A	1.07		1,241.20
	8-hour	A	0.72		835.20
NO_2	1-hour	A		27.60	51.89
	Annual	A		6.2	11.66
PM_{10}	24-hour	A			43.70
$PM_{2.5}$	24-hour	A			17.80
	Annual	A			6.00
SO_2	1-hour	A		5.2	13.62
	24-hour	A		2.4	6.29
	Annual	A		0.5	1.31
O_3	8-hour	A		54	106.01

[a] Grid Cell across the Road from TransAlta Centralia Station (Latitude 46.75 º N, Longitude 122.85 º W).

Table 3-5 presents the difference between the NAAQS and the representative background concentration, compared to the SILs. As shown in Table 3-5, all averaging periods for each pollutant have a margin between the monitored value and the NAAQS that is greater than the respective SIL; therefore, use of the SILs as *de minimis* levels for all pollutants is appropriate.

Table 3-5. Margin between Ambient Air Quality Concentrations and the NAAQS

Pollutant	Averaging Period	Background Concentration (µg/m³)	NAAQS (µg/m³)	Margin (NAAQS-Background) (µg/m³)	Significant Impact Level (µg/m³)
CO	1-Hour	1241.2	40,000	38,758.8	2,000
	8-Hour	835.2	10,000	9,164.8	500
NO_2	1-Hour	51.89	188	136.1	7.5
	Annual	11.66	100	88.3	1
PM_{10}	24-Hour	43.7	150	106.3	5
$PM_{2.5}$	24-Hour	17.8	35	17.2	1.2
	Annual	6.0	9	3.0	0.2
SO_2	1-Hour	13.62	196	182.4	1.2
	Annual	1.31	26.2	24.9	0.2
O_3	8-Hour	54 ppb	70 ppb	16 ppb	1 ppb

3.9 Modeling Methodology

The modeling analyses were conducted using the most current version of AERMOD (v24142) along with the meteorological data as described in Section 3.4. The analysis was conducted to demonstrate compliance with the NAAQS. The worst-case Unit #2 boiler operating condition was evaluated and modeled with other project sources as described in Section 3.2 to assess compliance with the NAAQS. If the maximum concentrations from any Project criteria pollutant emissions were predicted to be equal to or greater than their respective SILs, shown in Table 3-1, a modeling analysis including ambient background concentrations was conducted to determine compliance with the NAAQS.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3.9.1 NO_2 Modeling Methods

The NO_2 impact analysis was consistent with the EPA guidance on 1-hour NO_2 dispersion modeling, Guideline on Air Quality Models (EPA 2024a). The 2024 EPA guidance describes a multi-tiered screening approach for modeling 1-hour NO_2. The key issue is that NO_X emissions are released primarily in the form of nitric oxide, which convert to NO_2 in the atmosphere. Tier 1 in the screening approach assumes that all NO_X converts to NO_2. Tier 2 assumes NO_X converts to NO_2 at a rate consistent to an appropriate NO_2/NO_X ambient ratio derived from ambient measurement data. Tier 2 ARM2 method is a regulatory default conversion approach in AERMOD.

The Tier 2 ARM2 conversion methodology was used with the default minimum (0.5) and maximum (0.9) NO_2/NO_X ratios.

3.10 Assessment of Secondary Particulate and Ozone

The analysis of $PM_{2.5}$ impacts is consistent with the *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (USEPA 2022). If the Project has an annual potential to emit (PTE) of direct $PM_{2.5}$, NO_x, or SO_2 greater than their respective SER thresholds, air quality impacts from both primary and secondary $PM_{2.5}$ emissions must be assessed. For this Project, $PM_{2.5}$ and NO_x emissions are greater than their respective SERs, triggering the secondary $PM_{2.5}$ analysis. Impacts of primary $PM_{2.5}$ emissions were determined with dispersion modeling using AERMOD, as described above.

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in the 2024 *EPA Guideline on Air Quality Models*. This guideline promulgated a two-tier approach for addressing single-source impacts on 8-hour O_3 and 24-hour and annual secondary $PM_{2.5}$. A Tier 1 analysis was used, which involves the use of technically credible relationships between precursor emissions and secondary ambient impacts based on existing modeling studies deemed sufficient for evaluating a project source's impacts. Specifically, USEPA modeling described in the *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (USEPA 2019) was used. USEPA has generated empirical relationships between single sources and O_3 and $PM_{2.5}$ impacts for hundreds of hypothetical sources that vary in stack height, emission rate, and geographic location. The MERPs View Qlik application tool[4] was used. The tool provides illustrative hypothetical single-source modeled impacts for annual and daily maximum average $PM_{2.5}$ and annual maximum daily 8-hour O_3 for use in NAAQS Tier 1 demonstrations. The sources represented "high" releases (90 meters) and "low" releases (10 meters) at multiple emissions levels. For this Project, the high-level stack scenario is most appropriate because the Project Unit #2 stack height is 140.2 meters. Hypothetical sources were evaluated by USEPA at three geographic locations in Washington state; Klickitat in south central Washington approximately 168 km southeast of the Project site, Skagit located approximately 184 km north-northeast of the Project and situated along the bay, and Spokane which is approximately 425 km away in the eastern part of the state. The most representative hypothetical source for this Project is the Klickitat, Washington site. It is the closest to the Project site and the environment surrounding the Klickitat area is most like the Centralia area. Therefore, the Project estimates the expected secondary

[4] Located at https://www.epa.gov/scram/merps-view-qlik.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

$PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The hypothetical modeling results are scaled by the ratio of the USEPA scenario emission rate to the Project emission rate for each pollutant. The contributions to secondary $PM_{2.5}$ formation from the precursor emissions of NO_X and SO_2 are summed to estimate the total secondary $PM_{2.5}$. Total $PM_{2.5}$ impacts include the primary modeled $PM_{2.5}$ plus the estimated secondary $PM_{2.5}$ formed from precursor emissions.

Chemical transformations of NO_x and VOC contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional emissions. Section 5.3 of the *Guideline on Air Quality Models* recommends a two-tiered approach for an ambient O_3 analysis (USEPA 2024a). For this Project, NO_x and VOC emissions are greater than their respective SERs, triggering the requirement for an analysis of secondary formation of ozone. Like the analysis for secondary $PM_{2.5}$, a Tier 1 demonstration for O_3 formation was scaled from the existing USEPA modeling from the Klickitat site which was obtained using the MERPs View Qlik tool. To demonstrate the effect of Project emissions on regional O_3 levels, the estimated secondary formation of O_3 are compared to the USEPA 8-hour O_3 SIL, and if necessary, ambient background will be added to the secondary O_3 concentration for a NAAQS compliance demonstration.

3.11 Toxic Air Pollutant Source Impact analysis

Consistent with the first-tier review specified in both the current and 1998 version of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4 were evaluated with modeling. TAPs were modeled with AERMOD for each source that emits any of the eighteen TAPs that are being evaluated under the current rule and ten TAPs that are being evaluated under the 1998 rule. The AERMOD modeling was based on a unit emission rate of 1 gram/second (g/s). Then the TAP emission rates for each pollutant for each source were multiplied by modeled maximum normalized concentrations (assuming 1 g/s emission rates) and the contribution from each source summed to calculate a total impact concentration for each pollutant. This methodology is conservative because it sums all individual maximum impacts for a specific TAP for comparison with the ASIL thresholds regardless of where or when each maximum is predicted. The maximum predicted impacts from each source will likely not occur at the same time or at the same location. If this unit analysis shows noncompliance with the ASIL for any specific TAP, the TAP(s) were then modeled separately with specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact. This approach ensures that modeled impacts are not overestimated when compared to the ASIL.

4.0 AIR QUALITY MODELING RESULTS

4.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NO_x

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

and SO_2 emission are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NO_x and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of both natural gas and ultra low sulfur diesel fuel in Unit #2 (with worst-case impacts being modeled for each respective pollutant). The diesel usage was later eliminated from the project and Unit #2 will now only fire natural gas. This report includes the air dispersion modeling from that natural gas combustion and its associated impacts.

4.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2 and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios are provided in Appendix A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS and toxics modeling analyses.

4.3 Secondary Pollutant Assessment

4.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily (24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NO_x and SO_2 based on the USEPA photochemical modeling. The most representative USEPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The following calculations are used to estimate the Project only secondary $PM_{2.5}$ impacts.

For 24-hour secondary $PM_{2.5}$,

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

- NO_x – 3,000 tons/year (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.177 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.177 µg/m^3= 0.126 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.233 µg/m^3
  - Project SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.233 = 0.007 µg/m^3

Total 24-hour secondary $PM_{2.5}$ impact due to Project = 0.126 + 0.007 = **0.133 µg/m^3**

For annual secondary $PM_{2.5}$,

- NO_x – 3.000 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0084 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.0084 µg/m^3= 0.0060 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0086 µg/m^3
  - Facility SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.0086 = 0.0002 µg/m^3

Total annual secondary PM2.5 impact due to Project = 0.0060 + 0.0002 = 0.0062 µg/m3

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

4.3.2 Ozone Ambient Impact Assessment

Chemical transformation of NO_x and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing USEPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NO_x and VOC based on the USEPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the USEPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NO_x emissions and 500 tpy of VOC precursor emissions. The following calculations are used to estimate the Project only O_3 impacts.

- NO_x – 3,000 tpy (90 m source), Klickitat 8-hour O_3 impact = 7.954 ppb
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated O_3 impact due to Project = (2,134.7 /3000) * 7.954 ppb = 5.660 ppb
- VOC - 500 tpy (90 m source), Klickitat 8-hour O_3 impact = 0.031 ppb

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

- Project VOC emissions = 59.06 tpy
- Estimated O_3 impact due to Project = (59.06 /500) * 0.031 ppb = 0.004 ppb

Total 8-hour O3 impact = 5.660 + 0.004 = 5.664 ppb

4.4 Project Impacts Compared to the SILs

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 4-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 4-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

Table 4-1. SILs Analysis Results

Pollutant	Averaging Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	98.49[c]	7.5
	Annual	H1H	1.14[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	1.86 c	1.2
	Annual	H1H (5-year average)	0.26 c	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	5.66 ppb c	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

4.5 NAAQS Analysis

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

representative ambient background concentrations (as described in Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 4-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 4-2 are shown in contour plots provided in Appendix B.

Table 4-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117. 98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

4.6 Toxic Air Pollutant Modeling Results

Consistent with the first-tier review specified in both the current and 1998 versions of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4, Tables 2-6 and 2-8, were evaluated with AERMOD modeling. As described in Section 3.11, the modeling was first conducted based on a unit emission rate in a conservative unit analysis. Individual TAP modeling was conducted if the unit analysis showed noncompliance with the ASIL for any specific TAP, so as not to overestimate the TAP cumulative impacts. It should be noted that the refined receptor grid for annual impacts was incorporated into the toxics modeling and that impacts from the highest scenario for Unit #2 (i.e., 190 MW) were included in the TAP analysis results.

Table 4-3 shows the modeling results for the eighteen TAPs modeled for the current rule compared to the current ASILs. All TAPs demonstrate compliance with their respective ASILs. Individual TAP modeling was conducted for one TAP, Chromium VI. Chromium VI was the TAP closest to their ASIL at 79%. The next TAP closest to their ASIL is Silica, at 23% of its ASIL. Additionally, Silica's impact is expected to be lower than is shown in Table 4-3 because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 4-3 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
3-Methylcholanthrene	56-49-5	year	9.6E-05	4.7E-08	0%	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	year	8.5E-06	4.2E-07	5%	Yes
Benzene	71-43-2	year	1.3E-01	5.5E-05	0%	Yes
Dichlorobenzene	106-46-7	year	9.1E-02	3.1E-05	0%	Yes
Formaldehyde	50-00-0	year	1.7E-01	2.0E-03	1%	Yes
n-Hexane	110-54-3	24-hr	7.0E+02	1.5E+00	0%	Yes
Naphthalene	91-20-3	year	2.9E-02	1.6E-05	0%	Yes
Arsenic	7440-38-2	year	3.0E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	2.4E-04	2.9E-05	12%	Yes
Chromium VI[b]	18540-29-9	year	4.0E-06	3.2E-06	79%	Yes
Cobalt	7440-48-4	24-hr	1.0E-01	6.9E-05	0%	Yes
Lead	7439-92-1	year	8.3E-02	1.3E-05	0%	Yes
Manganese	7439-96-5	24-hr	3.0E-01	3.1E-04	0%	Yes
Mercury	7439-97-6	24-hr	3.0E-02	2.1E-04	1%	Yes
Nickel	7440-02-0	year	3.8E-03	5.5E-05	1%	Yes
Vanadium	7440-62-2	24-hr	1.0E-01	1.9E-03	2%	Yes
Silica	7631-86-9	24-hr	3.0E+00	6.8E-01	23%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.
[b] Chromium VI was modeled individually with its specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact.

Table 4-4 shows the modeling results for the ten TAPs modeled for the 1998 rule compared to the 1998 ASILs. All TAPs demonstrate compliance with their respective ASILs. Chromium VI was the TAP closest to their ASIL at 8%. Note that all impacts shown in Table 4-4 are conservative because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Table 4-4 1998 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
Benzene	71-43-2	year	1.2E-01	5.5E-05	0%	Yes
Formaldehyde	50-00-0	year	7.7E-02	2.0E-03	3%	Yes
n-Hexane	110-54-3	24-hr	2.0E+02	1.5E+00	1%	Yes
Arsenic	7440-38-2	year	2.3E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	5.6E-04	2.9E-05	5%	Yes
Chromium VI	18540-29-9	year	8.3E-05	6.6E-06	8%	Yes
Nickel	7440-02-0	year	2.1E-03	5.5E-05	3%	Yes
Vanadium	7440-62-2	24-hr	1.7E-01	1.9E-03	1%	Yes
PAH as benzo(a)pyrene	50-32-8	year	4.8E-04	3.1E-08	0%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

5.0 REFERENCES

Auer, August H. 1978. "Correlation of Land Use and Cover with Meteorological Anomalies" *Journal of Applied Meteorology*, Volume 17. Pp. 636-643.

Tetra Tech Inc. 2025. *Air Quality Dispersion Modeling Protocol*. Tetra Tech, Inc., Boston, MA 02109. September, 2025.

USEPA. 1985. *Guideline for the Determination of Good Engineering Practice Stack Height* (Technical Support Document for the Stack Height Regulation) – Revised. EPA-450/4-80-023R, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

USEPA. 2019. *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program*. Richard A. Wayland Memorandum. Office of Air Quality Planning and Standards, Research Triangle Park, NC. April 30, 2019.

USEPA. 2022. *Guidance for Ozone and Fine Particulate Matter Permit Modeling*. EPA-454/R-22-005. Office of Air Quality Planning and Standards, Research Triangle Park, NC. July 29, 2022.

USEPA. 2024a. Guideline on Air Quality Models; Enhancements to the AERMOD Dispersion Modeling System. Codified in the Appendix W to 40 CFR Part 51. Federal Register Vol. 89, No. 230, November 29, 2024, Rules and Regulations.

USEPA, 2024b. *User's Guide for the AMS/EPA Regulatory Model (AERMOD)*. EPA-454/B-24-007 (November 2024). Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX A: UNIT #2 LOAD ANALYSIS

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Unit #2 Load Analysis		100%	190 MW
Stack Temperature	°F	335.0	240.0
Stack Mass Flow	acfm	2,651,430	850,074
Stack Diameter	ft	24	24
Stack Velocity	ft/s	97.7	31.3
Stack Temperature	K	441.5	388.7
Stack Diameter	m	7.32	7.32
Exhaust Velocity	m/s	29.77	9.55
Emissions, Annual			
NOx Emissions	tpy	2131.97	1218.47
CO Emissions	tpy	2907.23	1661.55
PM10 Emissions	tpy	133.06	76.05
PM2.5 Emissions	tpy	133.06	76.05
Sulfur Dioxide	tpy	13.92	7.96
Emissions, Short-term (g/s)			
NO_x	g/s	103.95	35.05
CO	g/s	141.75	47.80
PM_{10}	g/s	6.49	2.19
$PM_{2.5}$	g/s	6.49	2.19
SO_2	g/s	0.68	0.23
Emissions, Annual (g/s)			
NO_x	g/s	61.33	35.05
SO_x	g/s	0.40	0.23
PM_{10}	g/s	3.83	2.19
$PM_{2.5}$	g/s	3.83	2.19

UNIT IMPACT, chi/Q (ug/m³ per g/s)		100%	190 MW
1-HR	1ST	0.63126	6.20683
8-HR	1ST	0.17836	3.08345
24-HR	1ST	0.07753	1.19912
1-HR	2ND	0.46679	6.20254
8-HR	2ND	0.15141	1.65954
24-HR	2ND	0.07569	0.73757
24-HR	6TH	0.06817	0.49674
ANNUAL	5-yr avg	0.01594	0.02831
ANNUAL Y1		0.01731	0.03220
ANNUAL Y2		0.01597	0.02836
ANNUAL Y3		0.01508	0.02637
ANNUAL Y4		0.01528	0.02624
ANNUAL Y5		0.01605	0.02862
Max. Indiv. Yr. Ann.		**0.01731**	**0.03220**

Worst Case Load Analysis - Unit 2 only (		100%	190 MW
1-hr NO_2 (full conversion)	H1H (5YA)	47.42412	135.7798
1-hr NO_2 (full conversion)	H8H (5YA)	40.84117	72.9494
Annual NO_2 (full conversion)	H1H	1.06	1.13
1-hr CO	H1H	89	297
1-hr CO	H2H	66	296
8-hr CO	H1H	25	147
8-hr CO	H2H	21	79
24-hr PM_{10}	H1H	0.50	2.62
24-hr PM_{10}	H6H	0.442	1.087
24-hr $PM_{2.5}$	H1H	0.45396	1.28112
24-hr $PM_{2.5}$	H8H	0.31579	0.45843
Annual $PM_{2.5}$	H1H (5YA)	0.06	0.06
1-hr SO_2	H1H (5YA)	0.30978	0.89097
1-hr SO_2	H4H (5YA)	0.28518	0.50281
24-hr SO2	H1H	0.05	0.27
24-hr SO2	H2H	0.05	0.17
Annual SO_2	H1H	0.007	0.007
Annual SO_2	H1H (5YA)	0.006	0.006

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX B: PROJECT PREDICTED CONCENTRATION CONTOURS FOR NAAQS ANALYSES

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

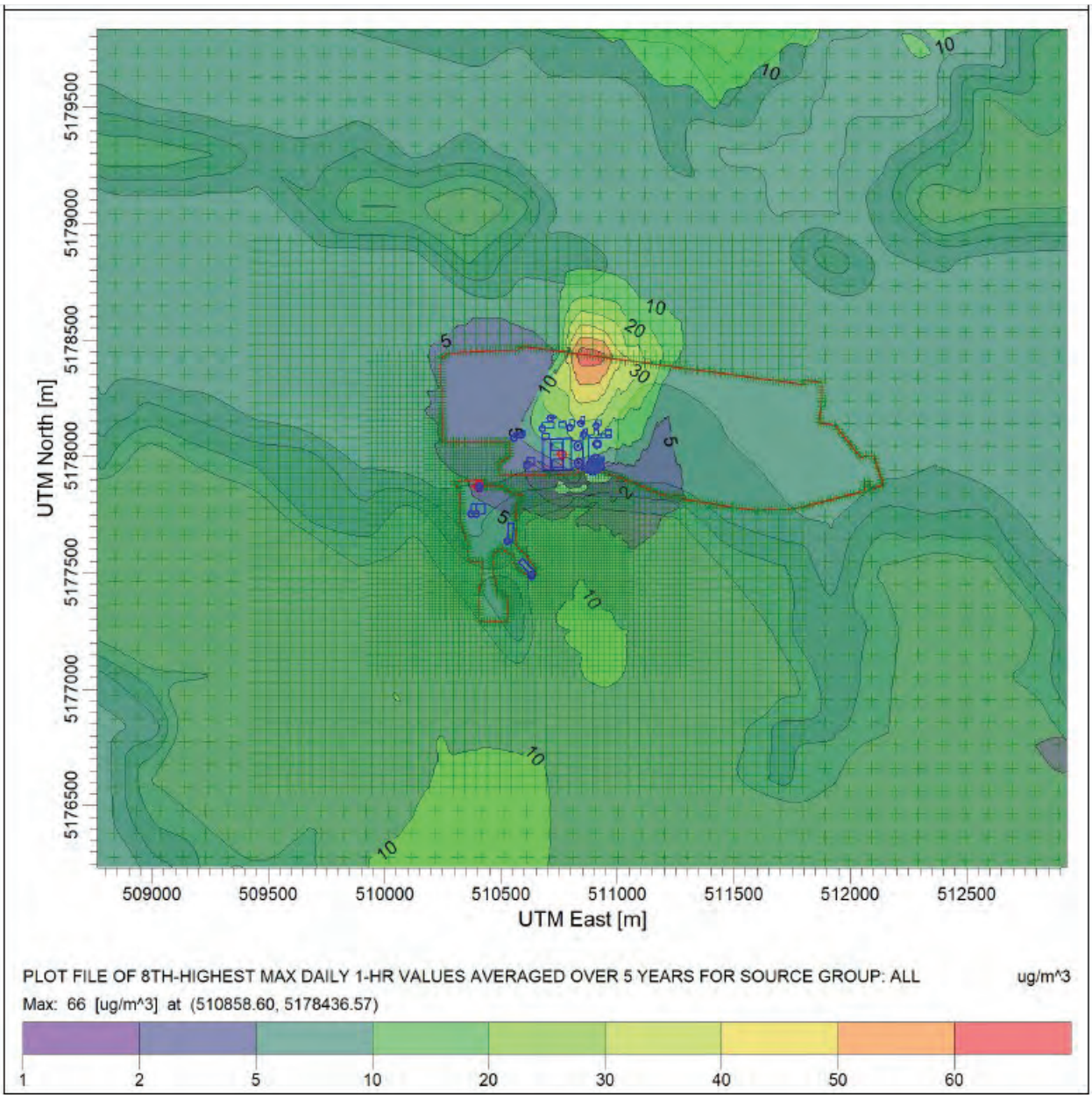


Figure B-1. AERMOD Predicted 1-hour NO_2 Concentration Contours

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

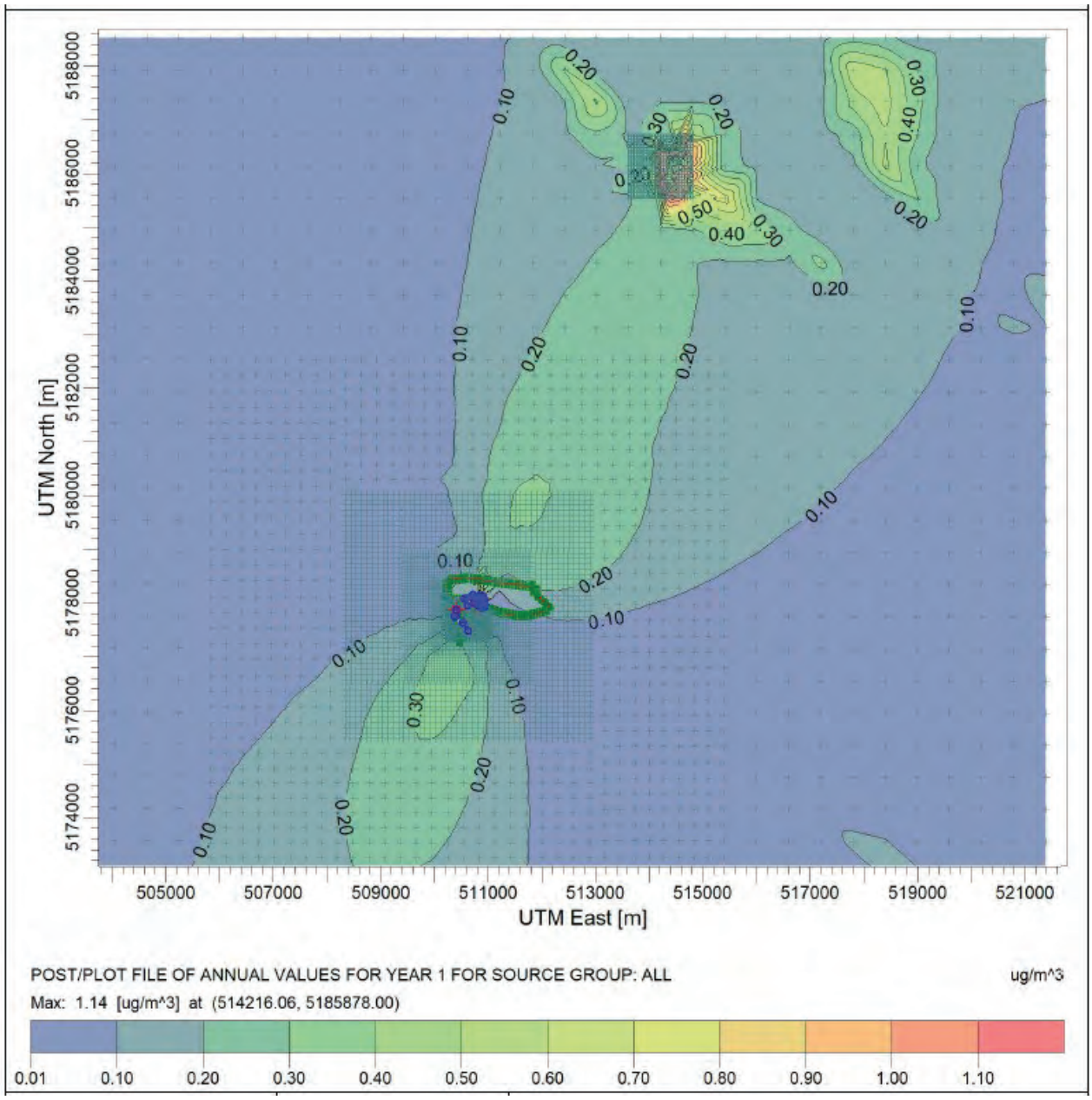


Figure B-2. AERMOD Predicted Annual (2020) NO_2 Concentration Contours

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

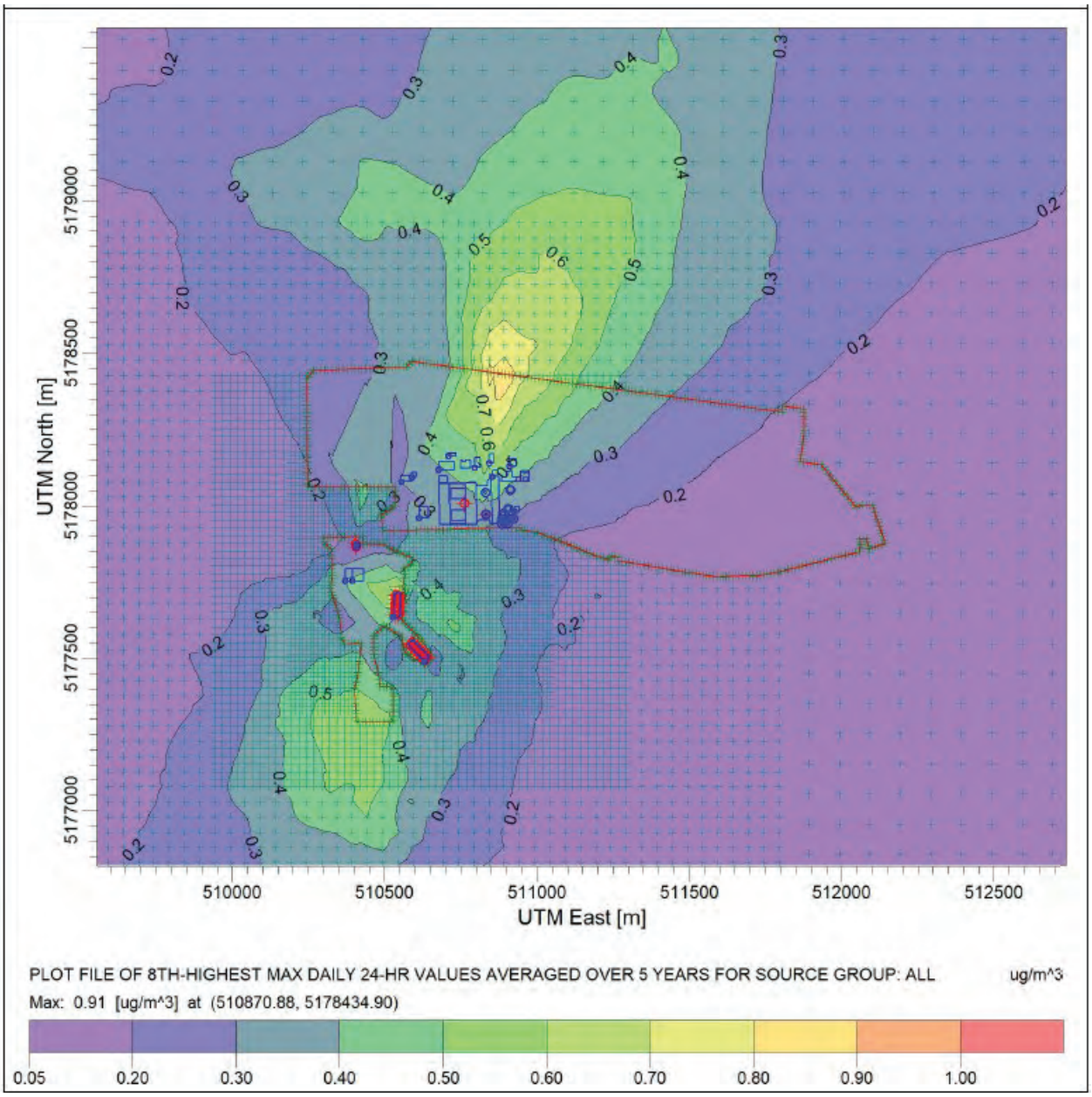


Figure B-3. AERMOD Predicted 24-Hour $PM_{2.5}$ Concentration Contours

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

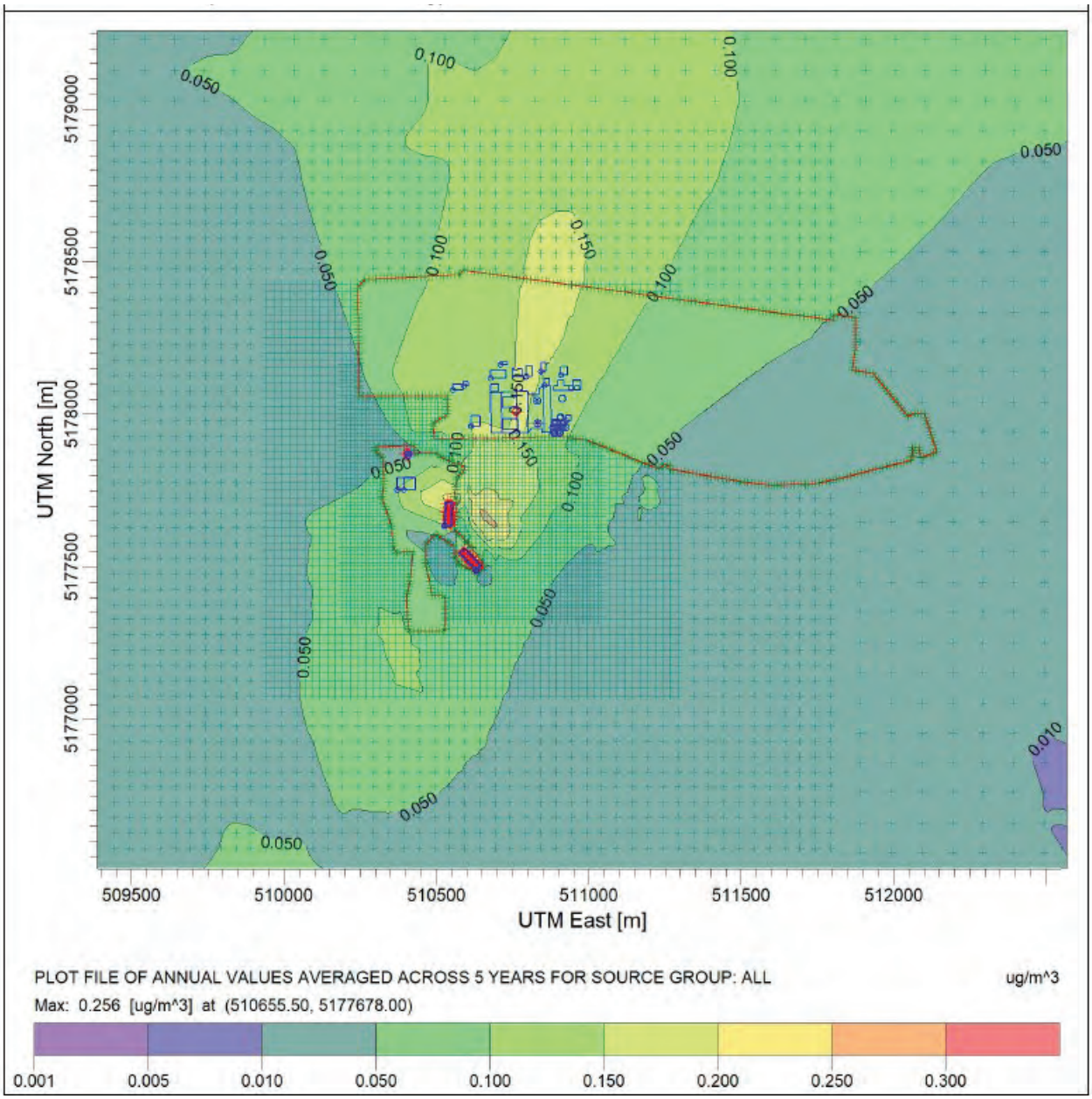


Figure B-4. AERMOD Predicted Annual $PM_{2.5}$ Concentration Contours

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

APPENDIX F: VISIBILITY MODELING ANALYSIS

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

CALPUFF Class I Visibility Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

TransAlta Centralia Generation Station

Centralia, Washington

December 2025

Prepared for

TransAlta
913 Big Hanaford Road
Centralia, Washington 98531

For Submittal to

Southwest Clean Air Agency
5101 NE 82nd Ave.
Vancouver, Washington 98662
and
Washington Dept. of Ecology
300 Desmond Drive SE
Lacey, Washington 98503

Prepared by



10 Post Office Square, 11th Floor
Boston, MA 02109

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

TABLE OF CONTENTS

1.0 INTRODUCTION 1

2.0 FACILITY DESCRIPTION 4

2.1 Site Location 4

2.2 Project Description 5

2.3 Summary of Annual Potential Emissions 5

3.0 CLASS I VISIBILITY IMPACT ASSESSMENT METHODOLOGY 7

3.1 Model Selection 7

3.2 Meteorological Data for CALPUFF 8

3.3 Model Domain 8

3.4 Source Data and Operating Scenarios 9

3.5 Class I Area Receptors 13

3.6 CALPUFF Model Options and Switch Settings 20

4.0 CLASS I VISIBILITY IMPACT ASSESSMENT RESULTS 22

5.0 REFERENCES 25

List of Tables

Table 2-1. Class I Areas within 300 km of the TransAlta Centralia Generation Station 5

Table 2-2. Project Annual Potential Emissions (tons per year, tpy) 6

Table 3-1. CALPUFF Domain LCC Projection Parameterizations 8

Table 3-2. Project BACT Summary 10

Table 3-3. Physical Stack Characteristics 11

Table 3-4. Stack Exhaust Parameters and Maximum Emission Rates used in the CALPUFF Modeling 12

Table 3-5. Number of Receptors at Each Class I Areas within 300 km of the TransAlta Centralia Generation Station 13

Table 3-6. CALPUFF Input Parameters for Deposition 20

Table 4-1. Natural Gas Conversion Project Visibility Improvement from 2010 BART Determination for the TransAlta Centralia Generation Station 23

Table 4-2. Predicted Number of Days with greater than 5% Change in Light Extinction at each Class I Area within 300 km of the TransAlta Centralia Generation Station 24

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

List of Figures

Figure 1-1. Facility Location Map 3
Figure 2-1. Project location with Class I Areas (white) within 300-km radius (circle) 4
Figure 3-1. CALPUFF Modeling Domain (LCC Projection) 9
Figure 3-2. Mount Rainier National Park Receptors Proposed for CALPUFF Modeling 14
Figure 3-3. Olympic National Park Receptors Proposed for CALPUFF Modeling 14
Figure 3-4. Goat Rocks Wilderness Area Receptors Proposed for CALPUFF Modeling 15
Figure 3-5. Mount Adams Wilderness Area Receptors Proposed for CALPUFF Modeling 15
Figure 3-6. Alpine Lakes Wilderness Area Receptors Proposed for CALPUFF Modeling 16
Figure 3-7. Mount Hood Wilderness Area Receptors Proposed for CALPUFF Modeling 16
Figure 3-8. Glacier Peak Wilderness Area Receptors Proposed for CALPUFF Modeling 17
Figure 3-9. Mount Jefferson Wilderness Area Receptors Proposed for CALPUFF Modeling 17
Figure 3-10. North Cascades National Park Receptors Proposed for CALPUFF Modeling 18
Figure 3-11. Pasayten Wilderness Area Receptors Proposed for CALPUFF Modeling 18
Figure 3-12. Mount Washington Wilderness Area Receptors Proposed for CALPUFF Modeling 19
Figure 3-13. Three Sisters Wilderness Area Receptors Proposed for CALPUFF Modeling 19

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Acronyms/Abbreviations

AMoN	Ammonia Monitoring Network
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BART	Clean Air Act Best Available Retrofit Technology
CALMET	The Meteorological Processing Model of the CALPUFF Modeling System
CALPOST	The Postprocessing Program of the CALPUFF Modeling System
CALPUFF	The CALPUFF Dispersion and Deposition Model
CTG	USGS composite theme grid land use files
dv	deciview
ddv	Delta-deciview
Ecology	Washington State Department of Ecology
FLAG	Federal Land Manager's Air Quality Related Values Work Group
FLM	Federal Land Manager
GHGs	greenhouse gases
HNO_3	nitric acid
H_2SO_4	sulfuric acid
IMPROVE	Interagency Monitoring of Protected Visual Environments
IWAQM	Interagency Workgroup on Air Quality Modeling
km	kilometer
LCC	Lambert Conformal Conic projection
m	meters
MMIF	EPA Mesoscale Model Interface Program
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NH_3	ammonia
NO_3^-	nitrates
NO_X	nitrogen oxides
NPS	National Park Service
O_3	ozone
PMC	coarse particulate matter with a diameter greater than 2.5 microns

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
The Project	Conversion of coal to natural gas firing in Unit 2 project
PSD	Prevention of Significant Deterioration
QA/QC	quality assurance/quality control
SO_2	sulfur dioxide
SO_4^{2-}	sulfate
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WRF	Weather Research Forecast Model

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility (Facility), which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application that requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. This facility is a recognized regional haze source and has Clean Air Act Best Available Retrofit Technology (BART) requirements in place. The BART program was instituted by Congress to reduce regional haze and restore visibility in national parks and wilderness areas (mandatory federal Class I areas). A CALPUFF visibility analysis was required for this Project because “any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled” (as described in the Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant, (Ecology, July 2020)). Detailed visibility modeling procedures were presented in the *CALPUFF Class I Visibility Modeling Protocol* submitted to the Southwest Clean Air Agency (SWCAA), Washington Department of Ecology (Ecology), and the Federal Land Managers (FLM) at the National Park Service (NPS), National Forest Service (NFS) and United States Fish and Wildlife Service (USFWS) on October 22, 2025. This document is the Class I visibility modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project’s location and expected emissions. Section 3 presents a detailed description of the modeling approach proposed for evaluating visibility impacts of the proposed Project including: source data, model selection, modeling domain, meteorological data, Class I Area receptors, CALPUFF model options, monthly ambient monitored ozone and ammonia background concentrations, as well as postprocessing for visibility impacts. Section 4 presents the visibility results at all Class I areas within 300 km of the Project. References cited in the document are presented in Section 5. To facilitate the review of this Report, the individual familiar with the CALPUFF

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

Modeling Consultant: Liz Hendrick, CCM
Tetra Tech, Inc.
10 Post Office Square, 11th Floor
Boston, MA 02109
Telephone: (978) 303-8524
Email: Liz.Hendrick@tetratech.com

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

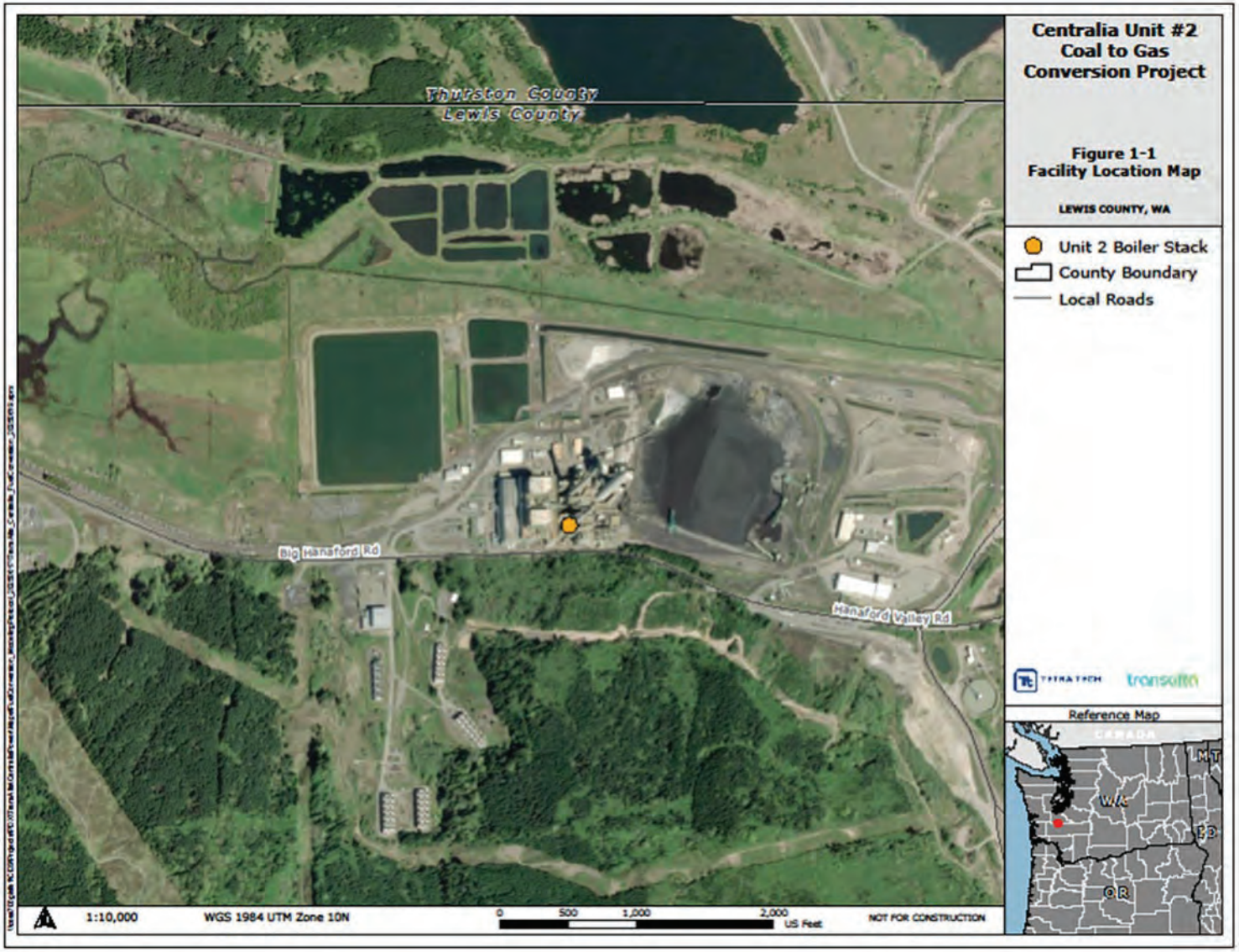


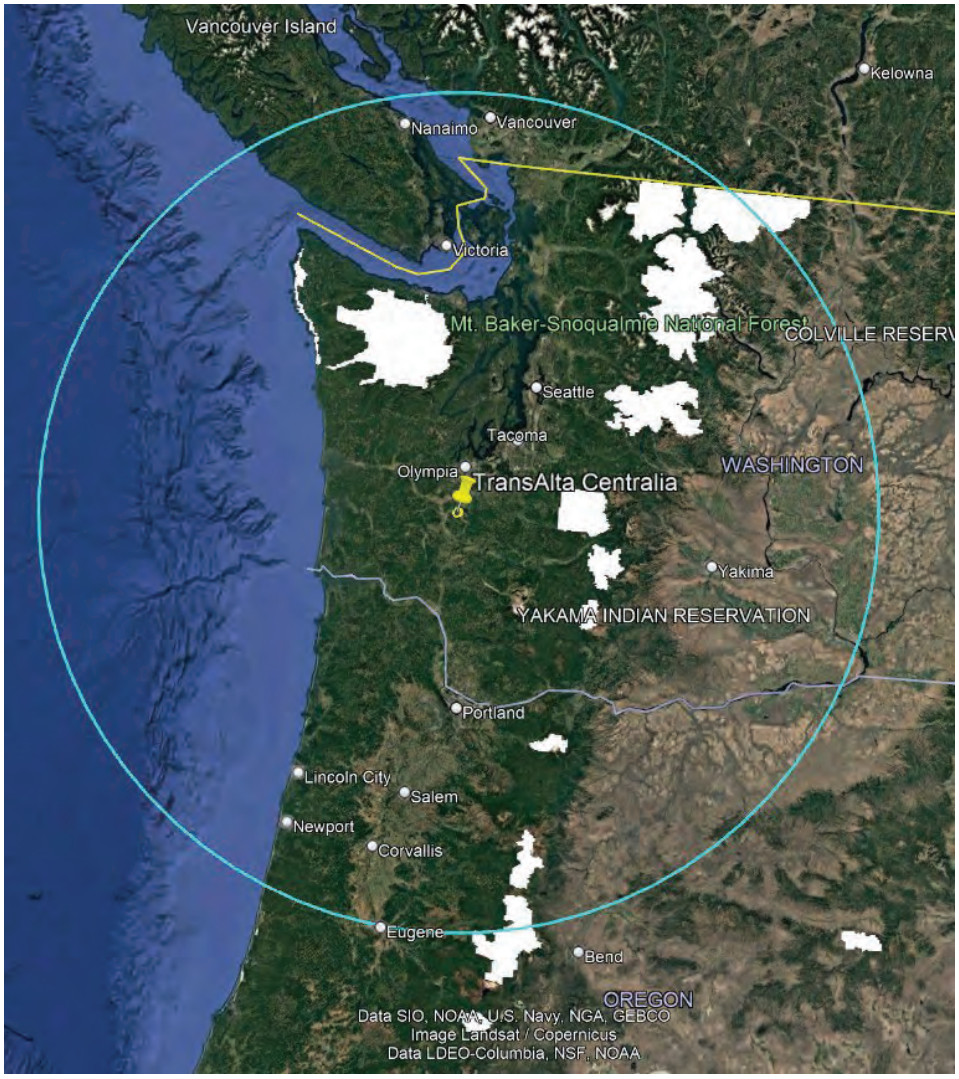
Figure 1-1. Facility Location Map

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

2.0 FACILITY DESCRIPTION

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land. Figure 2-1 presents an aerial graphic showing the TransAlta Plant location with a 300-kilometer (km) radius circle. The Class I areas are shown in white. There are 12 Class I areas within 300 km of the Project. Table 2-1 lists the Class I areas and closest distance from the Project Unit #2 stack to the nearest edge of the Class I area. A visibility analysis has been conducted for each Class I area.



Source: Google Earth

Figure 2-1. Project location with Class I Areas (white) within 300-km radius (circle)

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 2-1. Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Distance (km)
Mount Rainier National Park	71.7
Olympic National Park	90.3
Goat Rocks Wilderness Area	97.2
Mount Adams Wilderness Area	110.5
Alpine Lakes Wilderness Area	122.8
Mount Hood Wilderness Area	170.1
Glacier Peak Wilderness Area	185.0
Mount Jefferson Wilderness Area	230.2
North Cascades National Park	231.2
Pasayten Wilderness Area	260.9
Mount Washington Wilderness Area	273.7
Three Sisters Wilderness Area	286.5

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The project is not designed nor intended to operate continuously or at a high capacity or baseload factor. While additional modeling is needed, current expectations are that the facility will operate for less than 40% of hours on an annual basis over the life of the project; at a capacity factor of approximately 20% as the majority of operating hours are expected to be at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project includes the replacement of the existing diesel-fired auxiliary boiler with a new natural gas-fired auxiliary boiler, two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The facility's primary fuel will be natural gas, which will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boiler via a short 1300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-2. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied, as necessary. Potential emission rates for Unit #2 are based upon natural gas combustion at full load

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

operation for 5,168 hours per year (i.e., 59% capacity factor). Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year. Note: the pollutants in Table 2-2 are listed for completeness; not all are visibility-impacting pollutants.

Table 2-2. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[b,c]	Water Bath Heaters (2) [b,d]	Cooling Towers (2)	Project Wide Totals
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3.0 CLASS I VISIBILITY IMPACT ASSESSMENT METHODOLOGY

3.1 Model Selection

CALPUFF is a Lagrangian modeling system recommended for Class I area air quality impact assessments by the Federal Land Managers (FLM) Workgroup. From April 2003 until January 2017, CALPUFF was the USEPA's preferred model for assessing National Ambient Air Quality Standards (NAAQS) and/or Prevention of Significant Deterioration (PSD) increments in situations of long-range transport (at distances greater than 50 km [31 mi]) of emission sources. With the 2017 revisions to the Guideline on Air Quality Models (Appendix W to 40 CFR Part 51) (USEPA 2017), CALPUFF was delisted as a USEPA-preferred model, yet retained as a screening technique for long-range transport assessments for NAAQS and PSD increments. Nevertheless, the CALPUFF modeling system has remained the FLM's preferred model for assessing Air Quality Related Values (AQRV) at Class I areas and is used in this visibility assessment. AERMOD, a steady-state Gaussian model, is the USEPA's preferred model for regulatory applications within 50 km of a source and was used for this Project's NAAQS and toxics assessments. However, because the Class I areas are over 50 km away (Table 2-1) and AERMOD does not account for chemical transformations during long-range transport, it is unsuitable for the Class I visibility analysis. Therefore, CALPUFF is recommended for long-range visibility modeling. The current USEPA-approved version of CALPUFF, version 5.8.5, was used in this modeling analysis.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on the transport, transformation, dispersion, and removal of air pollutants. It treats emissions as a series of discrete puffs, each tracked individually until it exits the modeling domain. The model calculates each puff's contribution to receptor concentrations or deposition fluxes separately, allowing users to analyze individual source impacts or aggregate impacts over source groups.

CALPUFF utilizes three-dimensional meteorological fields generated by the CALMET model, which can be based on prognostic meteorological model outputs (e.g., the Weather Research and Forecasting model, WRF), station data (surface observations and upper air soundings), or a hybrid combination of both. CALPUFF can also accept prognostic meteorological data that is processed through the USEPA Mesoscale Model Interface Program (MMIF).

Designed for application over spatial scales ranging from tens to hundreds of kilometers, CALPUFF incorporates algorithms to address sub-grid scale effects such as terrain impingement, as well as longer-range processes including pollutant removal by wet scavenging and dry deposition, chemical transformations, and visibility impacts from particulate matter.

The model is especially well suited for complex flow situations involving spatially variable meteorological conditions influenced by factors like complex terrain or nearby water bodies. CALPUFF can simulate plume fumigation events (e.g., coastal fumigation or inversion breakup), low wind speed or calm conditions, and other scenarios where steady-state, straight-line models are inadequate. Additionally, it can assess the cumulative impact of multiple, spatially distributed sources with temporally varying emissions over large regions.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

CALPOST, the CALPUFF modeling system postprocessor, will be used to generate the visibility impacts from the CALPUFF runs of concentrations. The current USEPA-approved version is CALPOST version 6.221. CALPOST performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations.

CALPUFF View

CALPUFF View is a CALPUFF model graphical user interface (GUI) developed and maintained by Lakes Environmental (Ontario, Canada). The software amalgamates the various CALPUFF pre- and post-processing programs, providing a user-friendly model setup wizard interface and other tools to create a graphical display of the various model inputs and outputs for visualization and quality assurance/quality control (QA/QC). CALPUFF View has been specifically developed to facilitate long-range visibility and deposition assessments for Class I areas as described in the Federal Land Manager's Air Quality Related Values Work Group (FLAG) 2010, containing a database of the various parameters for each specific Class I area as defined in Tables 5 through 10 of FLAG 2010. The CALPUFF View software was used to facilitate the visibility modeling assessment.

3.2 Meteorological Data for CALPUFF

The USFWS provided three-dimensional gridded meteorological files for the 3-year period of 2018-2020 for use as input to CALPUFF. The USFWS prepared the files using the USEPA MMIF that converts prognostic meteorological model output fields to the parameters and formats required for direct input into CALPUFF. The CALPUFF meteorological grid has a 12 km horizontal resolution with ten vertical layers, defined as consistent with the default layers specified by USEPA/FLM guidance (cell face heights of 20, 40, 80, 160, 320, 640, 1200, 2000, 3000 and 4000 meters).

3.3 Model Domain

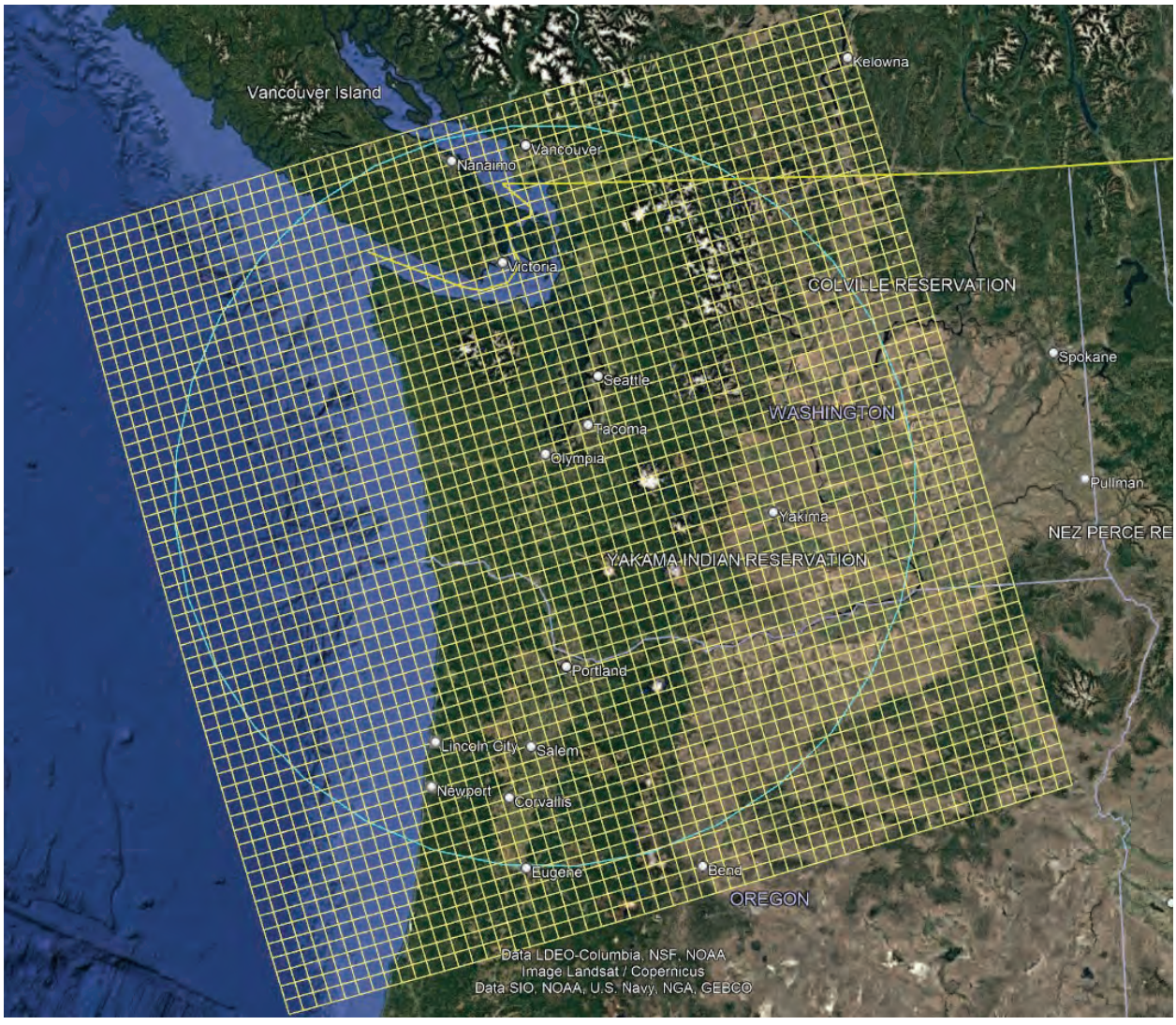
The modeling domain was defined by a 300 km radius with a buffer area beyond the radius (to allow for modeling of potential contaminant re-circulation), 660 km x 660 km, centered at Unit #2 at approximately 46.756°N, 122.858°W. The domain extends over the Pacific Ocean to the west, into Canada to the north and into Oregon to the south. Because the modeling domain covers such a large region, to account for the curvature of the earth, Lambert Conformal Conic (LCC) projection coordinates were used to define the meteorological grid points and source and receptor locations in CALPUFF. The parameterization of the CALPUFF domain is described in Table 3-1. The CALPUFF modeling domain is shown in Figure 3-1.

Table 3-1. CALPUFF Domain LCC Projection Parameterizations

CALPUFF Domain Parameter	Setting
XBTZ (Time Zone)	-8 (Pacific)
RLAT0 (degrees)	40.574°N
RLON0 (degrees)	97.000°W
XLAT (degrees)	33.000°N
XLAT2 (degrees)	45.000°N
NX	55
NY	55

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

CALPUFF Domain Parameter	Setting
NZ	10
DGRIDKM (km)	12
ZFACE (m)	0., 20, 40, 80, 160, 320, 640, 1,200, 2,000, 3,000, 4,000
XORIGKM (km)	-2268.0
YORIGKM (km)	618.0



Basemap: Google Earth

Figure 3-1. CALPUFF Modeling Domain (LCC Projection)

3.4 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year);

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) dew point (water bath) heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

As required by USEPA and Washington regulations, air permit applications for new major facilities must include a BACT review in accordance with 40 CFR 52.21(j) and WAC 173-400-830(1)(d) (for affected pollutants where the Project area is designated as an attainment area). Washington and Southwest Clean Air Agency (SWCAA) regulations also require a BACT review for minor new source review pollutants in accordance with WAC 173-400-030(13) and SWCAA 400-110. Table 3-2 lists the preliminarily proposed BACT control options for each source.

Table 3-2. Project BACT Summary

Source/Pollutant	Control Technology
Unit #2	
NO_X	Low NOx burners, combustion optimization system, flue gas recirculation
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel
Auxiliary Boiler	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)
Dew Point Heaters	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)

Table 3-3 summarizes the physical stack characteristics used in the modeling. Detailed emissions and source parameter data are provided in Table 3-4. The particulate matter is speciated into PMC (coarse particulate matter with a diameter greater than 2.5 microns) and $PM_{2.5}$ (particulate matter with a diameter equal to or less than 2.5 microns). For Class I visibility impairment modeling, the FLMs request that maximum 24-hour emission scenarios be evaluated. The Unit #2 boiler is modeled firing natural gas at full load (100%) assuming simultaneous operation of the auxiliary boiler, dew point heaters and cooling towers to determine total Project visibility impacts.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 3-3. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		LLC E (m)	LLC N (m)			
U2_100	Unit 2 Boiler (100% load)	-1950623.51	965448.66	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	-1950677.81	965513.85	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	-1951061.05	965475.59	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	-1951062.93	965466.73	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	-1951003.57	965214.12	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	-1950999.04	965226.47	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	-1950994.80	965239.08	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	-1950990.63	965250.83	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	-1950985.83	965264.70	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	-1950981.26	965277.22	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	-1950993.42	965209.71	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	-1950989.38	965222.20	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	-1950985.14	965234.82	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	-1950980.97	965246.56	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	-1950976.17	965260.44	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	-1950971.60	965272.95	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	-1950942.03	965051.80	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	-1950948.28	965063.42	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	-1950954.66	965075.60	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	-1950960.64	965087.92	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	-1950967.14	965100.10	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	-1950973.39	965111.69	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	-1950951.58	965046.56	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	-1950957.45	965058.54	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	-1950963.72	965070.32	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	-1950969.89	965082.56	93.96	19.91	7.62
COOLT2_K	Cooling Tower 2 Cell K	-1950976.30	965094.63	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	-1950982.53	965106.41	93.96	19.91	7.62

[a] Converted from UTM Zone 10, WGS-84 datum to Lambert Conformal Conic NWS-84 using the Lakes Environmental Coordinate Converter. Projection origin (Lat, Lon) = 40.574 deg N, 97.0 deg W with standard parallels of 33 deg N and 45 deg N.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 3-4. Stack Exhaust Parameters and Maximum Emission Rates used in the CALPUFF Modeling

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)				
			NO_x	PMC	$PM_{2.5}$	SO_2	SO_4
U2_100	441.48	29.77	103.948	0.0	6.488	0.679	0.010
AUXBLR	422.04	11.73	0.282	0.0	0.129	0.013	3.06-05
DPH_1	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
DPH_2	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
COOLT1_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_L	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_L	293.15	9.70	-	0.0015	0.0022	-	-

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

The CALPUFF modeling does not include building downwash, as the Class I areas are more than 50 km away from the sources. Downwash is the phenomena of disturbed atmospheric flow in the immediate vicinity of a structure that results in higher ground-level concentrations at a closer proximity to the source than would otherwise occur if the structures were not there. For long-range transport it is more conservative to allow the plume to travel undisturbed by local structures.

3.5 Class I Area Receptors

The National Park Service (NPS) provides receptors for use in Class I area modeling analyses. There are a total of 5,881 receptors in the Class I areas within 300 km of the source. Table 3-5 lists the number of receptors at each Class I area provided by the NPS and used in this modeling analysis.

Table 3-5. Number of Receptors at Each Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Number of Receptors
Mount Rainier National Park	405
Olympic National Park	714
Goat Rocks Wilderness Area	181
Mount Adams Wilderness Area	313
Alpine Lakes Wilderness Area	693
Mount Hood Wilderness Area	310
Glacier Peak Wilderness Area	444
Mount Jefferson Wilderness Area	183
North Cascades National Park	888
Pasayten Wilderness Area	931
Mount Washington Wilderness Area	359
Three Sisters Wilderness Area	460

The Class I receptor locations are provided by the NPS in latitude/longitude format. CALPUFF View allows for the direct download and import of Class I area receptors into the model and converts them to LCC format for use in CALPUFF consistent with the original WRF projection. The receptor elevations provided in the NPS receptor file were used in the CALPUFF modeling.

The receptors used in the modeling in each Class I area are shown in Figures 3-2 through 3-13 (figures courtesy of the NPS website). Some of the Class I areas straddle the 300 km radius circle with the nearest receptors within 300 km of TransAlta Centralia and some of the receptors beyond 300 km. The modeling domain is large enough so that the Class I area receptors were modeled (including those that are beyond 300 km from the source).

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

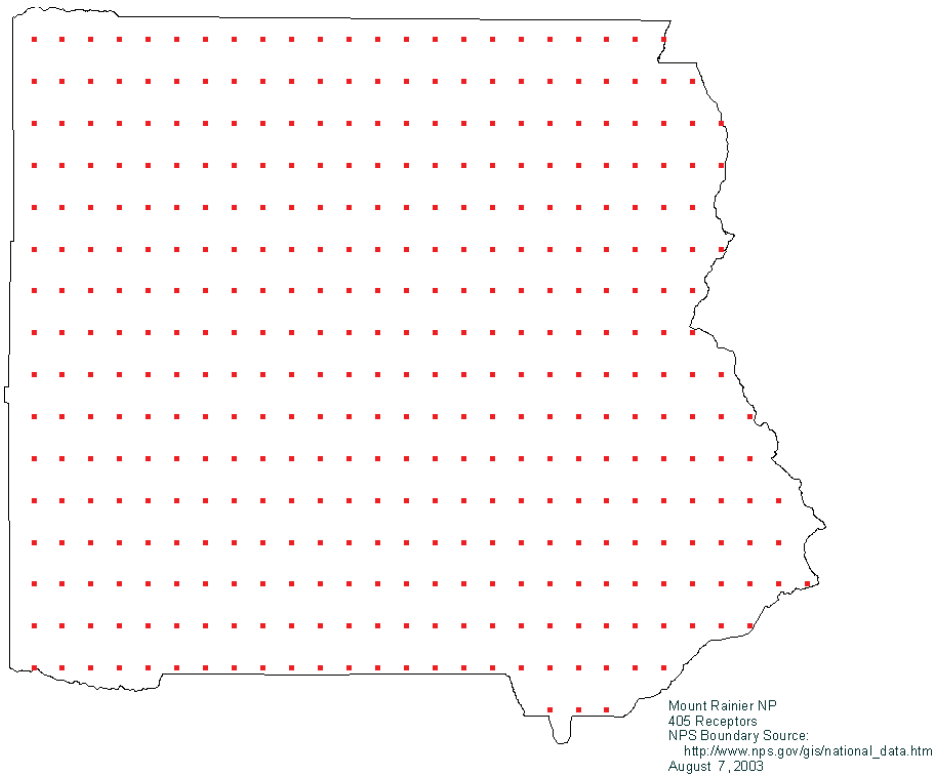


Figure 3-2. Mount Rainier National Park Receptors Proposed for CALPUFF Modeling

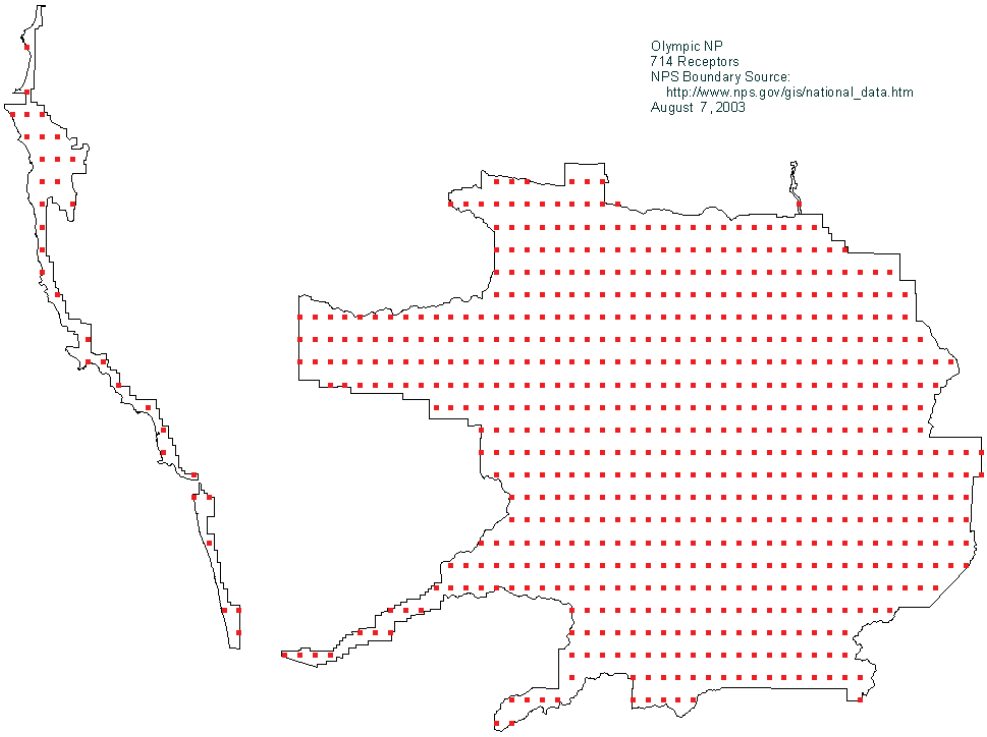


Figure 3-3. Olympic National Park Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

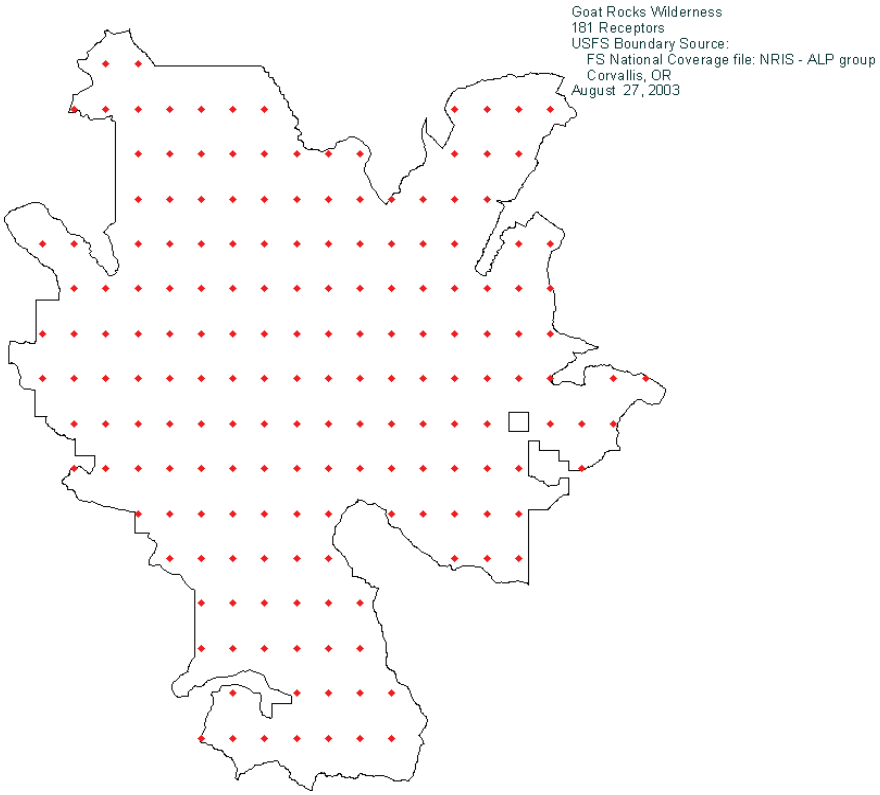


Figure 3-4. Goat Rocks Wilderness Area Receptors Proposed for CALPUFF Modeling

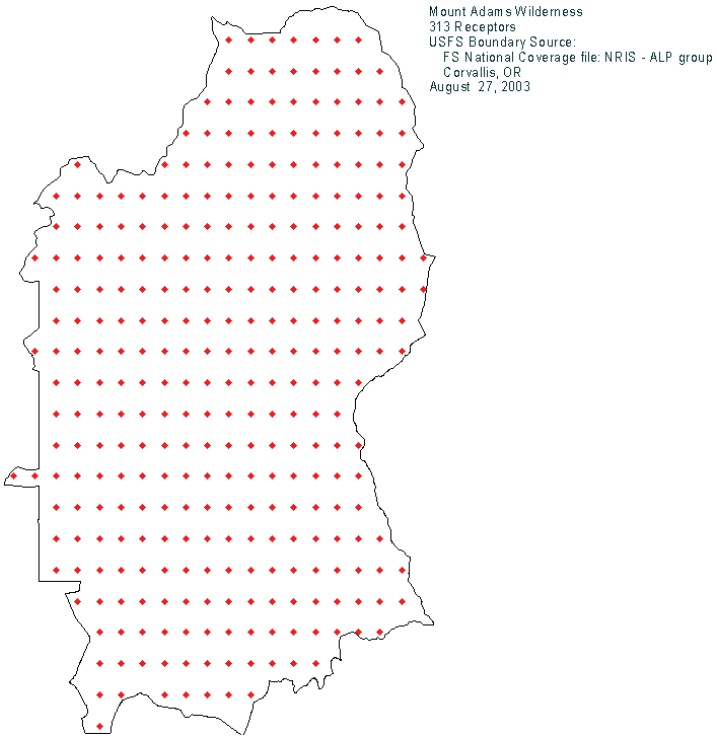


Figure 3-5. Mount Adams Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

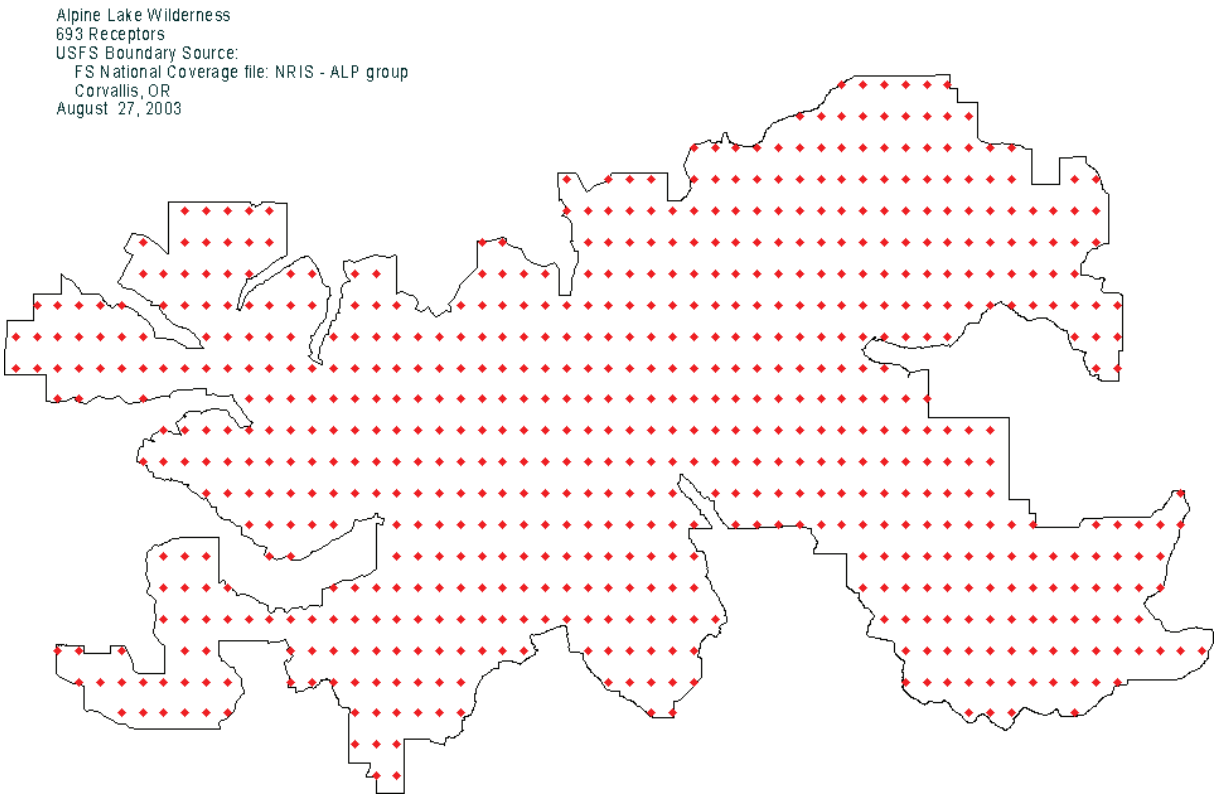


Figure 3-6. Alpine Lakes Wilderness Area Receptors Proposed for CALPUFF Modeling

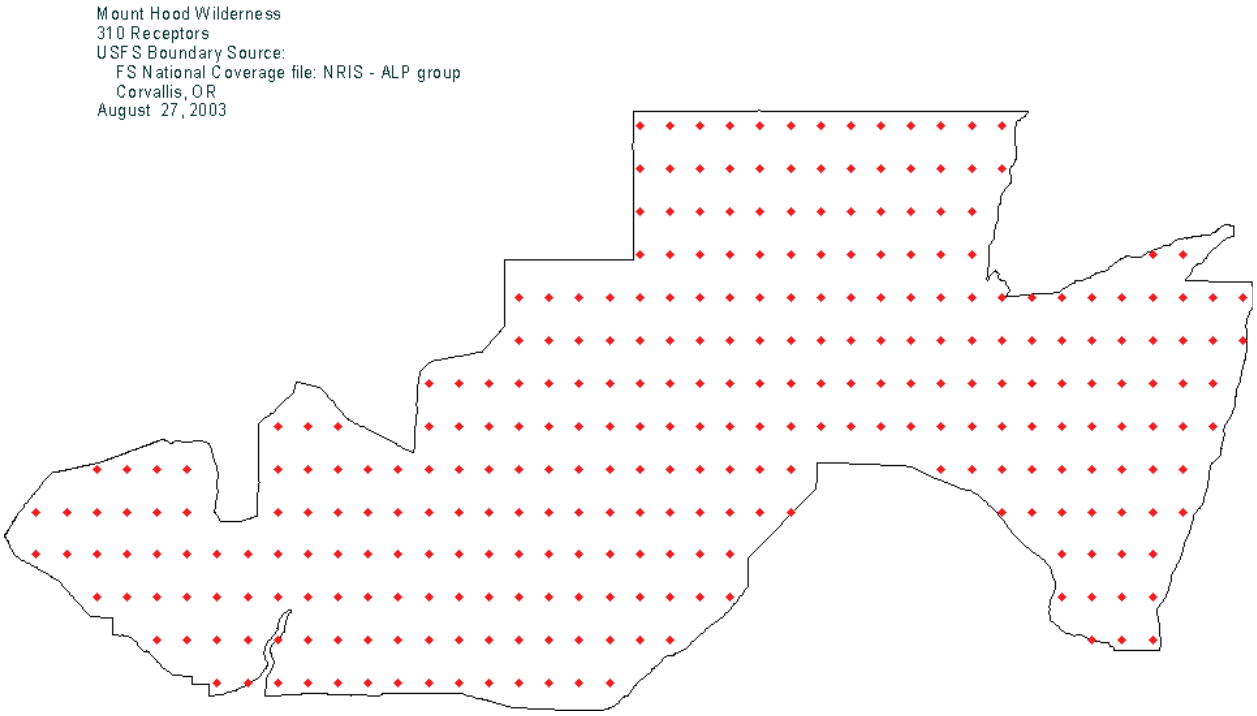


Figure 3-7. Mount Hood Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

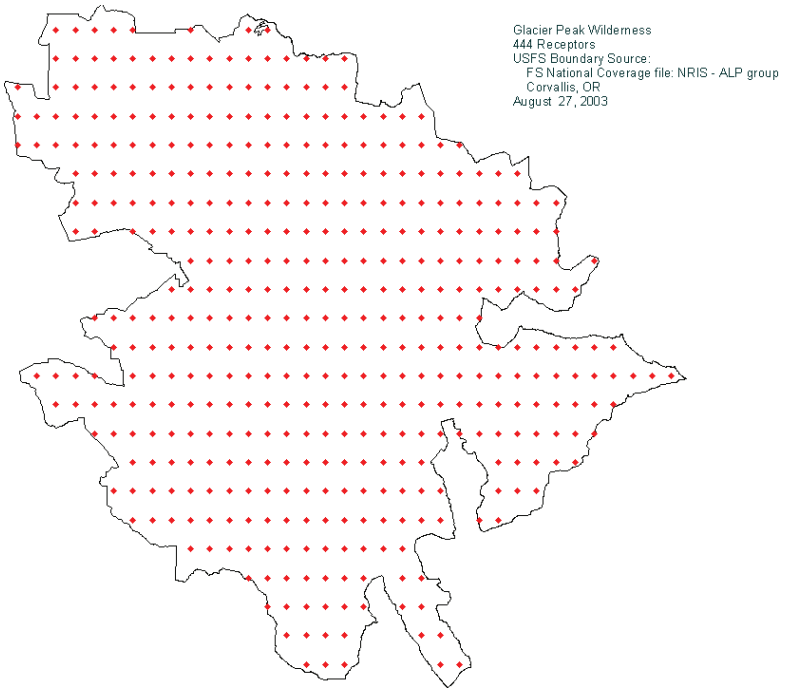


Figure 3-8. Glacier Peak Wilderness Area Receptors Proposed for CALPUFF Modeling

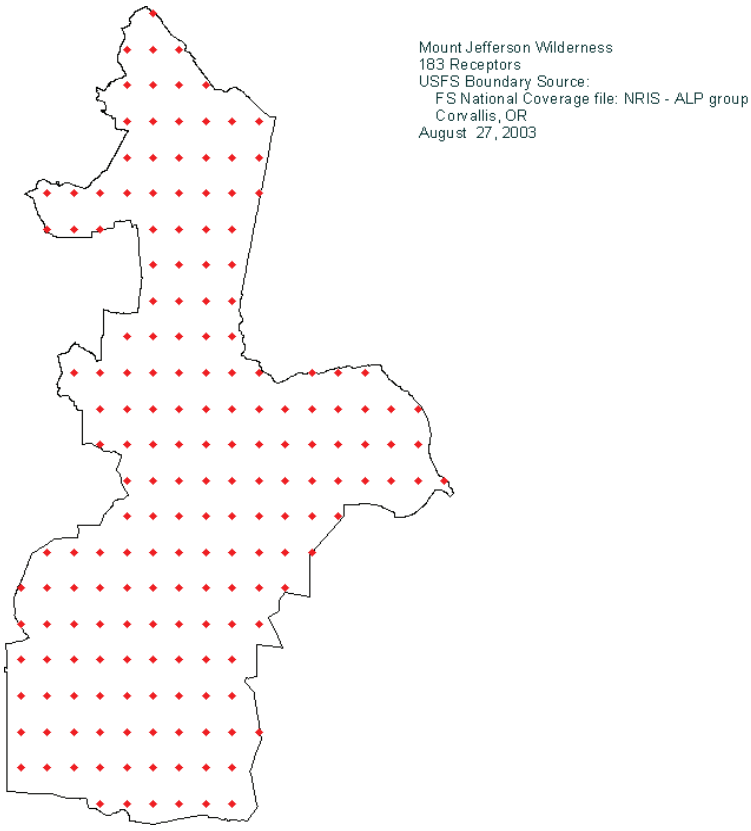


Figure 3-9. Mount Jefferson Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884



Figure 3-10. North Cascades National Park Receptors Proposed for CALPUFF Modeling

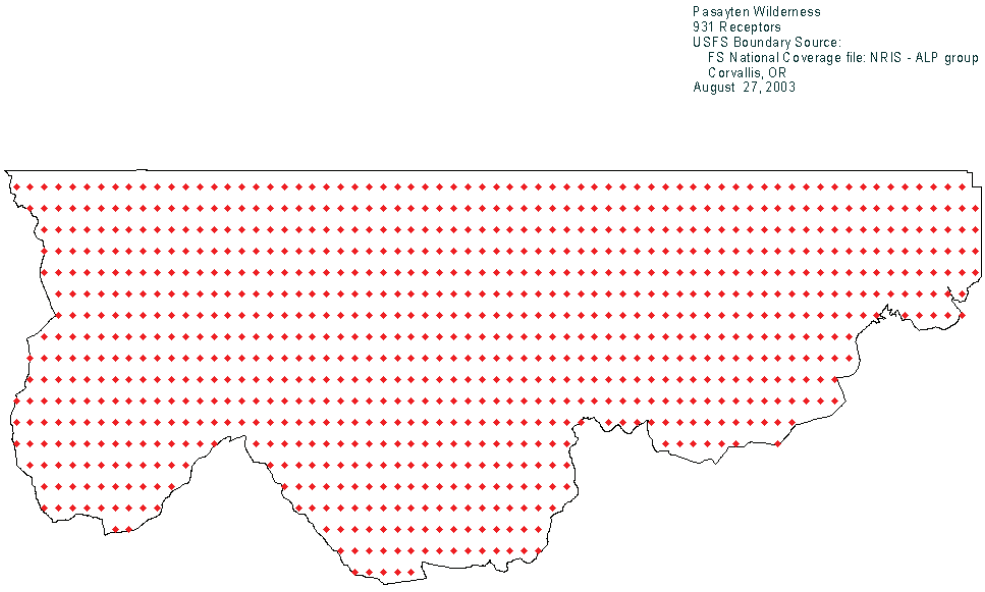


Figure 3-11. Pasayten Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

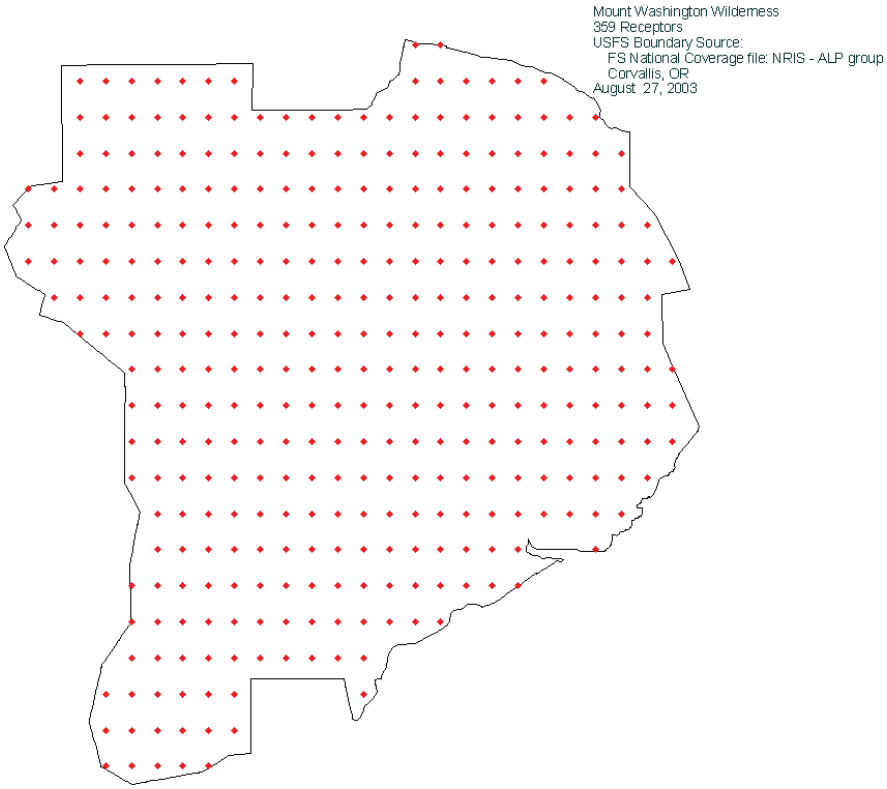


Figure 3-12. Mount Washington Wilderness Area Receptors Proposed for CALPUFF Modeling

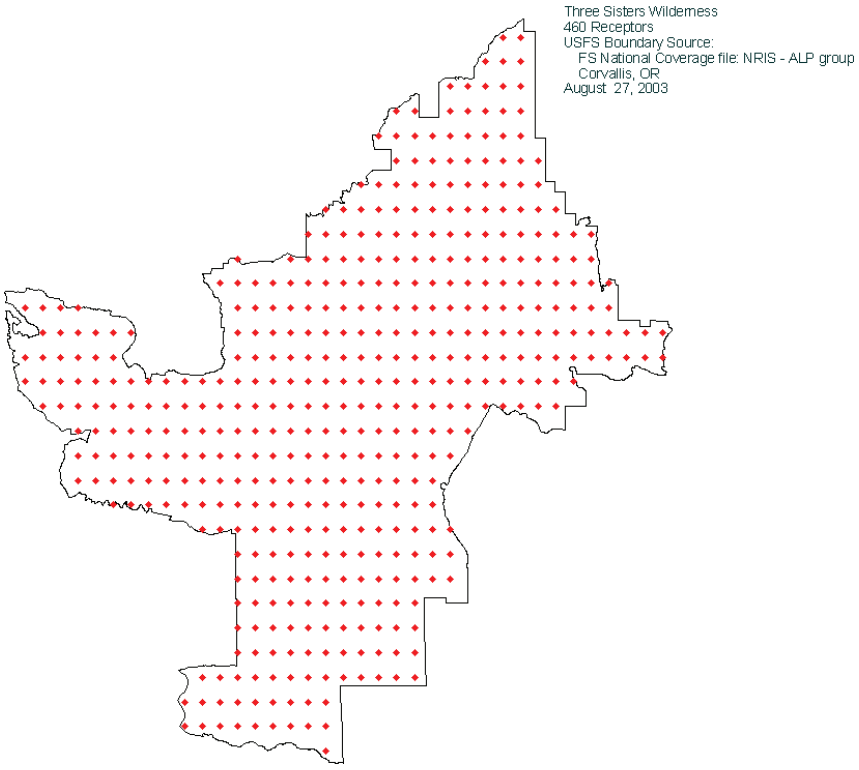


Figure 3-13. Three Sisters Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

3.6 CALPUFF Model Options and Switch Settings

The CALPUFF switch settings used in the modeling correspond to the regulatory options specified in Appendix B of the IWAQM Phase 2 document (EPA 1998).

Both dry and wet deposition were modeled using CALPUFF's default depositional parameters. Gaseous phase dry deposition was modeled for NOx, HNO_3, and SO_2, while particle deposition was assumed for NO_3-, SO_4^{2-} as well as particulate matter. H_2SO_4 emissions were treated as primary SO_4^{2-}. Default scavenging coefficients for the wet deposition algorithm provided in CALPUFF were used for SO_2, SO_4^{2-}, HNO_3, NH_3, NO_3^-, PMC and $PM_{2.5}$. The deposition parameters used in the modeling are presented in Table 3-6.

Table 3-6. CALPUFF Input Parameters for Deposition

Parameter	SO_2	NO_X	HNO_3	NH_3
Dry Deposition of Gases				
Diffusivity (cm^2/s)	0.1509	0.1656	0.1628	0.23
Alpha Star	1000	1	1	1
Reactivity	8	8	18	18
Mesophyll Resistance (s/cm)	0	5	0	0
Henry's Law Coefficient	0.04	3.5	8.0E-8	7.0E-7
	SO_4	NO_3-	PMC	$PM_{2.5}$
Dry Deposition of Particles				
Geometric Mass Mean Diameter (microns)	0.48	0.48	0.48	0.48
Geometric Standard Deviation (microns)	2.0	2.0	2.0	1.5
Other Dry Deposition Parameters				
Reference cuticle resistance (s/cm)		30		
Reference ground resistance (s/cm)		10		
Reference pollutant reactivity		8		
Number of particle-size intervals		9		
Vegetation state in unirrigated areas		Active and unstressed		

Pollutant	Scavenging Coefficient Liquid (1/sec)	Scavenging Coefficient Frozen (1/sec)
Precipitation Scavenging Coefficients		
SO_2	3.0×10^{-5}	0
SO_4	1.0×10^{-4}	3.0×10^{-5}
NO_X	0	0
HNO_3	6.0×10^{-5}	0
NH_3	7.9×10^{-5}	3.0×10^{-5}
NO_3-	1.0×10^{-4}	3.0×10^{-5}
$PM_{2.5}$	1.0×10^{-4}	3.0×10^{-5}
PMC	1.0×10^{-4}	3.0×10^{-5}

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Chemical transformations of NOx to nitrates (NO_3^-) and nitric acid (HNO_3), and SO_2 to sulfate (SO_4^{2-}) were evaluated using CALPUFF's MESOPUFF II chemistry scheme as recommended for long-range transport in IWAQM 1998. The rate of chemical transformations in the MESOPUFF II scheme is dependent on the concentration of ozone and ammonia in the ambient air. Representative ozone concentrations for May through September were defined on a monthly basis as the average of 8-hour observations at the Lacey-Olympia air quality monitor (Monitor ID #53-067-0013) located approximately 22.5 miles to the north-northeast of the source. This is the closest most representative monitor but only operates during the ozone season. For the remainder of the year (i.e., January through April and October through December) the data set was supplemented with observations from the Seattle monitor (Monitor ID #53-033-0080). The Seattle monitor is approximately 66 miles to the northeast of the source and operates year-round. The monitored ozone concentrations at the Lacey-Olympia and Seattle monitors are similar during the ozone season months; therefore, the Seattle monitor can serve as a suitable surrogate for the rest of the year. There is an ozone monitor on Mount Rainier, which is slightly closer to the source (~62 miles to the east) than the Seattle monitor, but it is situated at an elevation of 1615 meters. Both the Lacey-Olympia and the Seattle monitors are at base elevations (70 m and 105 m, respectively) much closer to the source base elevation (between 68-93m). Therefore, the Lacey-Olympia and Seattle ozone data are more representative of background concentrations near the source than the Mount Rainier data. The ozone concentrations from the most recently available three-year period (2022-2024) were used.

Washington state has only one ambient monitor measuring ammonia concentrations, which is part of the Ammonia Monitoring Network (AMoN). This monitor, AMoN-WA99, is in Mount Rainier National Park at an elevation of 424 meters, lower than the nearby ozone monitor. Monthly background ammonia concentrations were calculated using data collected from 2022 to 2024.

The CALPUFF modeling system postprocessor, CALPOST will be used to generate the visibility impacts from the CALPUFF runs. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest EPA/FLM recommendations. CALPOST will run separately for each Class I area for each year modeled. The CALPOST parameter MVISBK will be set to 8, sub-mode five (M8_MODE = 5), and the background hygroscopic and non-hygroscopic aerosol levels are derived from the annual average natural conditions for each Class I area as provided in Table 6 of the FLAG 2010 guidance. When calculating the sulfate and nitrate components of the visibility extinction coefficient, relative humidity adjustment factors are applied because these aerosols are hygroscopic, and the addition of water enhances their scattering efficiencies. The monthly relative humidity adjustment factors from Tables 7 through 9 in FLAG 2010 for each Class I area are input to the RHFAC array in CALPOST (which are auto-populated for each specific Class I area by the CALPUFF View software).

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

4.0 CLASS I VISIBILITY IMPACT ASSESSMENT RESULTS

Visibility is typically characterized by visual range (VR) - the greatest distance at which a large dark object can be seen - or by the light-extinction coefficient (b_{ext}), which measures light attenuation per unit distance due to scattering and absorption by atmospheric gases and particles (EPA 1998). A constant fractional change in b_{ext} produces a similar perceptual change in a scene regardless of baseline conditions. Based on this perceived visual change, an alternate visibility index called the deciview (dv) has been defined by the USEPA's Regional Haze Rule (USEPA, 1999). This unitless index is a logarithmic scale based on the light extinction coefficient (b_{ext}), specifically designed to correlate with human perception. It ensures that uniform changes in haziness correspond to consistent incremental changes in perceived visibility across the full range of conditions, from pristine to highly impaired. The deciview scale increases as visibility worsens. The delta deciview (ddv) is the difference between total visibility and natural visibility, quantifying the impairment caused by human-generated pollution.

The visibility impairment threshold of concern for Class I areas is not exceeded if the 98th percentile change in light extinction is less than 5% for each modeled year when compared to the annual average natural condition value. The 98th percentile test applies to the number of days that any modeled receptor in a Class I area exceeds the 5% degradation threshold. If the analysis indicates the 98th percentile value of change in light extinction is equal to or greater than 5% for any year (i.e., 5% change exceeded on 8 or more days per year), then FLAG 2010 guidance indicates the results may be further scrutinized to determine the frequency of the exceedances and the conditions under which the exceedances are predicted.

CALPOST, the CALPUFF modeling system postprocessor, was used to generate visibility impacts from the CALPUFF output. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations. For the assessment of a 24-hour average regional haze visibility impact, light extinction was determined as a function of the modeled concentrations of primary (H_2SO_4) and secondary sulfate (SO_4^{2-}), secondary nitrate (NO_3^-), nitrogen dioxide (NO_2, assumed as 100% of NO_X emissions) and fine and coarse particulate matter ($PM_{2.5}$ and PMC, respectively) based on maximum allowable 24-hour mass emission rates.

The CALPUFF visibility analysis was conducted for this Project because any request to repower one or both units at the Centralia plant requires modeling the impact of repowering on visibility, as stated in the Technical Support Document for the Second BART Order Revision – TransAlta Centralia Generation Plant (July 2020). When the plant operated two coal-fired units, TransAlta prepared visibility impairment modeling following the Oregon/Idaho/Washington/USEPA Region 10 BART modeling protocol. Ecology prepared a BART Determination Support Document in 2009, revised in 2010 (Ecology, 2010). Ecology determined that BART controls for NOx and SO_2 would "result in a visibility improvement from the baseline impacts at Mount Rainier National Park of approximately 1.13 dv, with improvements of 0.67 to 1.45 dv at other affected Class I areas" (Ecology, 2010).

The conversion from two coal-fired units to a single natural gas unit will further reduce emissions and enhance visibility in these Class I areas. Table 4-1 summarizes the expected visibility improvements based on the Project's predicted CALPUFF modeling results compared to the 2010 BART

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

determination. In 2010, four control scenarios were evaluated against the baseline operation; Table 4-1 presents the control scenario with the lowest deciview change (ddv) from the Ecology 2010 BART Determination, representing the cleanest outcome. The improvement of visibility is shown as a range in Table 4-1 because the 2010 document reported only the maximum of three years of modeling, while the current analysis includes results for all three years modeled.

All twelve Class I areas within 300 km of the Project will experience significant visibility improvements. The largest improvement is predicted at Mount Rainier National Park, with a 2.459 ddv reduction, and the smallest at Pasayten Wilderness Area, with a 0.619 ddv reduction.

Table 4-1. Natural Gas Conversion Project Visibility Improvement from 2010 BART Determination for the TransAlta Centralia Generation Station

Class I Area	Natural Gas Conversion Project Largest Predicted Delta Deciview (ddv)			2010 BART [a] Single year Lowest Control Scenario (ddv)	Range of Visibility Improvement (reduction in ddv)
	2018	2019	2020		
Mount Rainier National Park	1.069	1.302	0.900	3.359	2.057 – 2.459
Olympic National Park	1.148	1.075	0.322	2.506	1.358 – 2.184
Goat Rocks Wilderness Area	1.035	0.674	0.835	3.069	2.034 – 2.395
Mount Adams Wilderness Area	0.695	0.575	0.695	1.984	1.289 – 1.409
Alpine Lakes Wilderness Area	0.602	0.904	0.679	2.949	2.045 – 2.347
Mount Hood Wilderness Area	0.243	0.661	0.233	1.978	1.317 – 1.745
Glacier Peak Wilderness Area	0.297	0.320	0.216	2.036	1.716 – 1.820
Mount Jefferson Wilderness Area	0.148	0.148	0.163	1.150	0.987 – 1.002
North Cascades National Park	0.209	0.263	0.239	1.570	1.307 – 1.361
Pasayten Wilderness Area	0.456	0.196	0.211	1.075	0.619 – 0.879
Mount Washington Wilderness Area	0.130	0.136	0.115	1.106	0.970 – 0.991
Three Sisters Wilderness Area	0.126	0.150	0.158	1.139	0.981 – 1.013

[a] Data obtained from Table 3-1 in the 2010 BART Determination (Ecology, 2010)

Table 4-2 presents the results of light extinction calculations for each of the twelve Class I areas within 300 km of the Project. It shows the predicted maximum change in light extinction and the number of days per year with a predicted change exceeding 5%. Note that the 98th percentile threshold for a change in light extinction of 5% or more is considered exceeded if it occurs on 8 or more days per year. For ten of the twelve Class I areas modeled, predicted changes in light extinction do not exceed the 98th percentile threshold in any modeled year. At the closest Class I area, Mount Rainier National Park, the predicted change exceeds the threshold by 2 days for both 2018 and 2020 meteorological conditions, and by 8 days in 2019. At the Goat Rocks Wilderness Area, the threshold is exceeded by 2 days in 2018 but not exceeded in 2019 or 2020.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

Table 4-2. Predicted Number of Days with greater than 5% Change in Light Extinction at each Class I Area within 300 km of the TransAlta Centralia Generation Station

Class I Area	Approx. Distance and Direction from Project	Number of Days >5% Change in Light Extinction		
		2018	2019	2020
Mount Rainier National Park	71.7 km to E	9	**15**	9
Olympic National Park	90.3 km to NNW	3	2	0
Goat Rocks Wilderness Area	97.2 km to ESE	9	3	7
Mount Adams Wilderness Area	110.5 km to SE	3	1	2
Alpine Lakes Wilderness Area	122.8 km to NE	1	2	5
Mount Hood Wilderness Area	170.1 km to SSE	0	1	0
Glacier Peak Wilderness Area	185.0 km to NNE	0	0	0
Mount Jefferson Wilderness Area	230.2 km to SSE	0	0	0
North Cascades National Park	231.2 km to NNE	0	0	0
Pasayten Wilderness Area	260.9 km to NNE	0	0	0
Mount Washington Wilderness Area	273.7 km to SSE	0	0	0
Three Sisters Wilderness Area	286.5 km to SSE	0	0	0

Note: Bold font indicates the 98th percentile value (i.e., 8 days or more per year) is exceeded.

Although Table 4-2 shows four exceedances of the visibility impairment threshold, these results should be interpreted in the context of the modeling assumptions. The CALPUFF model assumes continuous plant operation - 24 hours a day, every day of the year at full load. In reality, the plant will not be a baseload facility, and it is being permitted to operate up to an annual capacity factor of 59%, or approximately 215 days per year with varying levels of operation, the majority of which are expected to be at half-load or minimum stable generation levels (see Section 2.2). Therefore, the frequency of visibility impairment on the 98th percentile worst days must be considered alongside the likelihood that meteorological conditions causing higher visibility impacts will coincide with the days the plant is operational.

Docusign Envelope ID: C94F0B90-6841-4872-A59F-98E6846D4884

5.0 REFERENCES

Earth Tech, Inc., 2000. A *User's Guide for the CALPUFF Dispersion Model (Version 5)*. Concord, Massachusetts 01742. January 2000.

Ecology, 2010. BART Determination Support Document for TransAlta Centralia Generation, LLC Power Plant, Centralia, Washington. Washington Department of Ecology – Air Quality Program, August 2009, revised April 2010.

Ecology, 2020. Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant. Washington Department of Ecology – Air Quality Program, July 2020.

NPS (National Park Service). 2010. Federal Land Manager's Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010), U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service. Natural Resources Report NPS/NRPC/NRR-2010/232, October.

USEPA, 1998. Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. EPA-454/R-98-019 (November 2024). Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711. December 1998.

USEPA, 1999. Regional Haze Regulations. Federal Register Vol. 64, No. 126, Thursday, July 1, 1999, Rules and Regulations.

USEPA, 2017. Revisions to the Guideline on Air Quality Models; Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter. Codified in the Appendix W to 40 CFR Part 51. Federal Register Vol. 82, No. 10, January 17, 2017, Rules and Regulations.

Certificate Of Completion

Envelope Id: C94F0B90-6841-4872-A59F-98E6846D4884
Status: Completed
Subject: Complete with Docusign: TA_CTG_ADP Application_01-12-2026_Compiled.pdf
Source Envelope:
Document Pages: 238
Signatures: 2
Envelope Originator:
Certificate Pages: 5
Initials: 0
Marina Tufts
AutoNav: Enabled
1100 - 1st Street SE
EnvelopeId Stamping: Enabled
Calgary, AB T2G 1B1
Time Zone: (UTC-07:00) Mountain Time (US & Canada)
marina_tufts@transalta.com
IP Address: 142.152.64.152

Record Tracking

Status: Original
1/13/2026 8:57:05 AM
Holder: Marina Tufts
marina_tufts@transalta.com
Location: DocuSign

Signer Events	Signature	Timestamp
Conrad Wieclaw conrad_wieclaw@transalta.com Engineering and Environmental Manager Security Level: Email, Account Authentication (None)	 Signature Adoption: Pre-selected Style Using IP Address: 63.228.223.150	Sent: 1/13/2026 9:00:34 AM Viewed: 1/13/2026 9:03:05 AM Signed: 1/13/2026 9:05:55 AM
Electronic Record and Signature Disclosure: Accepted: 1/13/2026 9:03:05 AM ID: 938f1500-009f-47b2-a297-302d937a0f91		

In Person Signer Events	Signature	Timestamp

Editor Delivery Events	Status	Timestamp

Agent Delivery Events	Status	Timestamp

Intermediary Delivery Events	Status	Timestamp

Certified Delivery Events	Status	Timestamp

Carbon Copy Events	Status	Timestamp
Vincent Light vincent_light@transalta.com Security Level: Email, Account Authentication (None)	COPIED	Sent: 1/13/2026 9:05:59 AM
Electronic Record and Signature Disclosure: Accepted: 7/24/2025 2:57:41 PM ID: 0c96112a-1f2b-404b-bd30-29659763776f		
Andrea Ortega andrea_ortega@transalta.com Senior Environmental Planner Security Level: Email, Account Authentication (None)	COPIED	Sent: 1/13/2026 9:06:00 AM
Electronic Record and Signature Disclosure: Accepted: 10/28/2025 6:49:46 PM ID: 10e6f9ab-a7e1-4caf-aa0c-a87c715e4b3e		

Witness Events	Signature	Timestamp

Notary Events	Signature	Timestamp

Envelope Summary Events	Status	Timestamps
Envelope Sent	Hashed/Encrypted	1/13/2026 9:00:34 AM
Certified Delivered	Security Checked	1/13/2026 9:03:05 AM
Signing Complete	Security Checked	1/13/2026 9:05:55 AM
Completed	Security Checked	1/13/2026 9:06:00 AM

Payment Events	Status	Timestamps

Electronic Record and Signature Disclosure

ELECTRONIC RECORD AND SIGNATURE DISCLOSURE

From time to time, TransAlta Corporation (we, us or Company) may be required by law to provide to you certain written notices or disclosures. Described below are the terms and conditions for providing to you such notices and disclosures electronically through the DocuSign system. Please read the information below carefully and thoroughly, and if you can access this information electronically to your satisfaction and agree to this Electronic Record and Signature Disclosure (ERSD), please confirm your agreement by selecting the check-box next to 'I agree to use electronic records and signatures' before clicking 'CONTINUE' within the DocuSign system.

Getting paper copies

At any time, you may request from us a paper copy of any record provided or made available electronically to you by us. You will have the ability to download and print documents we send to you through the DocuSign system during and immediately after the signing session and, if you elect to create a DocuSign account, you may access the documents for a limited period of time (usually 30 days) after such documents are first sent to you. After such time, if you wish for us to send you paper copies of any such documents from our office to you, you will be charged a $0.00 per-page fee. You may request delivery of such paper copies from us by following the procedure described below.

Withdrawing your consent

If you decide to receive notices and disclosures from us electronically, you may at any time change your mind and tell us that thereafter you want to receive required notices and disclosures only in paper format. How you must inform us of your decision to receive future notices and disclosure in paper format and withdraw your consent to receive notices and disclosures electronically is described below.

Consequences of changing your mind

If you elect to receive required notices and disclosures only in paper format, it will slow the speed at which we can complete certain steps in transactions with you and delivering services to you because we will need first to send the required notices or disclosures to you in paper format, and then wait until we receive back from you your acknowledgment of your receipt of such paper notices or disclosures. Further, you will no longer be able to use the DocuSign system to receive required notices and consents electronically from us or to sign electronically documents from us.

All notices and disclosures will be sent to you electronically

Unless you tell us otherwise in accordance with the procedures described herein, we will provide electronically to you through the DocuSign system all required notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you during the course of our relationship with you. To reduce the chance of you inadvertently not receiving any notice or disclosure, we prefer to provide all of the required notices and disclosures to you by the same method and to the same address that you have given us. Thus, you can receive all the disclosures and notices electronically or in paper format through the paper mail delivery system. If you do not agree with this process, please let us know as described below. Please also see the paragraph immediately above that describes the consequences of your electing not to receive delivery of the notices and disclosures electronically from us.

How to contact TransAlta Corporation:

You may contact us to let us know of your changes as to how we may contact you electronically, to request paper copies of certain information from us, and to withdraw your prior consent to receive notices and disclosures electronically as follows:
To contact us by email send messages to: HR_Services@transalta.com

To advise TransAlta Corporation of your new email address

To let us know of a change in your email address where we should send notices and disclosures electronically to you, you must send an email message to us at HR_Services@transalta.com and in the body of such request you must state: your previous email address, your new email address. We do not require any other information from you to change your email address.

If you created a DocuSign account, you may update it with your new email address through your account preferences.

To request paper copies from TransAlta Corporation

To request delivery from us of paper copies of the notices and disclosures previously provided by us to you electronically, you must send us an email to HR_Services@transalta.com and in the body of such request you must state your email address, full name, mailing address, and telephone number. We will bill you for any fees at that time, if any.

To withdraw your consent with TransAlta Corporation

To inform us that you no longer wish to receive future notices and disclosures in electronic format you may:

i. decline to sign a document from within your signing session, and on the subsequent page, select the check-box indicating you wish to withdraw your consent, or you may;

ii. send us an email to HR_Services@transalta.com and in the body of such request you must state your email, full name, mailing address, and telephone number. We do not need any other information from you to withdraw consent.. The consequences of your withdrawing consent for online documents will be that transactions may take a longer time to process..

Required hardware and software

The minimum system requirements for using the DocuSign system may change over time. The current system requirements are found here: https://support.docusign.com/guides/signer-guide-signing-system-requirements.

Acknowledging your access and consent to receive and sign documents electronically

To confirm to us that you can access this information electronically, which will be similar to other electronic notices and disclosures that we will provide to you, please confirm that you have read this ERSD, and (i) that you are able to print on paper or electronically save this ERSD for your future reference and access; or (ii) that you are able to email this ERSD to an email address where you will be able to print on paper or save it for your future reference and access. Further, if you consent to receiving notices and disclosures exclusively in electronic format as described herein, then select the check-box next to 'I agree to use electronic records and signatures' before clicking 'CONTINUE' within the DocuSign system.

By selecting the check-box next to 'I agree to use electronic records and signatures', you confirm that:

- You can access and read this Electronic Record and Signature Disclosure; and
- You can print on paper this Electronic Record and Signature Disclosure, or save or send this Electronic Record and Disclosure to a location where you can print it, for future reference and access; and
- Until or unless you notify TransAlta Corporation as described above, you consent to receive exclusively through electronic means all notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you by TransAlta Corporation during the course of your relationship with TransAlta Corporation.

EXHIBIT 103-2

SWCAA
Southwest Clean Air Agency

11815 NE 99th Street, Suite 1294
Vancouver, WA 98682
(360) 574-3058
www.swcleanair.gov

February 25, 2026 VIA ELECTRONIC MAIL

Conrad Wieclaw
TransAlta Centralia Generation
913 Big Hanaford Road
Centralia, WA 98531

Subject: Completeness Determination for Air Discharge Permit Application L-760

Dear Conrad Wieclaw:

The Southwest Clean Air Agency (SWCAA) received your Air Discharge Permit (ADP) Application for repowering Unit #2 with natural gas on January 13, 2026, with application fees paid on January 26, 2026. This application has been designated as ADP application L-760.

SWCAA has determined, after review, that the application is currently incomplete. Additional information is needed before SWCAA can complete review of the application. Please provide the following additional information:

1. A visibility impact analysis for the Columbia River Gorge National Scenic Area.
2. Itemization of Unit #2 retrofit costs. This information is necessary to document whether the retrofit meets the definition of "reconstruction."
3. For Unit #2:
    a. The make and model of the new natural gas fired burners, and an installation schematic or drawing showing where and how many burners are proposed for installation;
    b. The maximum turndown of each burner;
    c. Whether the angle of the burners will be adjustable, and if so, the range of adjustment;
    d. The proposed range of flue gas recirculation (FGR), and how the FGR rate will be controlled;
    e. An installation schematic or drawing showing where and how many overfire air ports are proposed for installation or re-use, whether the angle of the overfire air will be adjustable, and if so, the range of adjustment, and the overfire air adjustment range;
    f. The permit application utilizes an "anticipated emissions rate" of 0.12 lb/MMBtu NO_X for emissions calculations as the base case for the BACT analysis and proposed emission limit. Please include documentation of how this value was derived and any vendor guarantees or other supporting documentation; and
    g. The permit application utilizes an "anticipated emissions rate" of 0.15 lb/MMBtu CO for emissions calculations as the base case for the BACT analysis and proposed emission limit. Please include documentation of how this value was derived and any vendor guarantees or other supporting documentation.

4. For the Auxiliary Boiler:
    a. The make and model of the boiler;
    b. The make and model of the burners; and
    c. Whether the boiler will utilize an oxygen trim system.
5. For the water bath heaters:
    a. The make and model of the heaters;
    b. The make and model of the burners; and
    c. Whether the heaters will utilize an oxygen trim system.
6. For the cooling towers:
    a. The make and model of the cooling towers and the mist eliminators.

Unit #2 BACT Analysis

7. Documentation of site-specific costs for urea, electricity, fuel, and water to be used in the BACT cost evaluation of selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and hybrid SNCR/SCR systems. These site-specific costs should be used for the best available control technology (BACT) cost analyses.
8. A BACT analysis comparing the cost-effectiveness of the following NO_X control options for Unit #2. The basis for all costs should be documented:
    a. Different natural gas burners from the same or different manufacturers, if a range of emissions guarantees or performance exists;
    b. SNCR using a control efficiency of 25% or better. Please utilize capital costs that account for the re-use of existing components of the SNCR system or a justification of why any particular portion of the existing SNCR system cannot be returned to service.
    c. SCR; and
    d. Hybrid SCR/SNCR.

    Where a range of costs and effectiveness exists for a specific control technology within a reasonable range of cost-effectiveness, these control options should be compared.

SWCAA may accept alternative information if it satisfies the intent of the above requests.

Please note that after submittal of the above information, SWCAA may still request additional information during the forthcoming permitting process for the purpose of clarifying selected elements of the application.

I look forward to working with you to complete the permitting process. If you need further assistance or have any questions regarding the requested information, please contact me at (360) 574-3058 extension 131 or by email at clint@swcleanair.gov.

Regards,

Clint H Lamoreaux

Clint Lamoreaux
Air Quality Engineer

EXHIBIT 104

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-18

DECLARATION OF CALLAHAN MORIYASU
IN SUPPORT OF SECOND REHEARING FILING

Background and Qualifications

1. I am currently employed as a Supervising Regulatory Analyst with the Public Counsel Unit of the Washington State Office of the Attorney General. In this role, I serve as an in-house expert on utility regulation and oversee and direct the work of other Regulatory Analysts. I have submitted testimony and written formal comments in several cases related to energy and electricity. I have a Master of Public Policy degree from the University of Southern California, as well as a Bachelor of Arts in Economics and History from Northwestern University. In addition to my formal education, I have completed several utility ratemaking courses, including New Mexico State University's Electricity Regulatory Training Course, Michigan State University's Power Grid School, and NARUC's Rate School and Fundamentals of Electricity Course.

Purpose of This Affidavit

2. This affidavit addresses the impact of the February 2026 unplanned outage of the Columbia Generating Station (CGS), which was managed without the need to operate or ramp up TransAlta Centralia Generation's Unit 2.

CGS Capacity and Contribution to the Grid

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

3. With a nameplate capacity of 1200 MW, CGS is the largest non-hydroelectric generation facility in Washington.[1] In 2024, CGS generated 9.97 million MWh of energy, or 10% of all energy produced by the Total Electric Power Industry in the state.[2] CGS can supply enough electricity to power 1 million homes.[3]

Table 1: 2024 Net Generation in Washington – Total Electric Power Industry[4]

Energy Source	Generation (MWh)	Percent of Total
Hydroelectric Conventional	60,736,309	59%
Natural Gas	18,097,481	18%
Nuclear	9,967,139	10%
Wind	8,863,339	9%
Coal	2,846,594	3%
Wood and Wood Derived Fuels	999,314	1%
Solar Thermal and Photovoltaic	436,826	<1%
Other Gases	222,601	<1%
Other Biomass	110,507	<1%
Other	72,471	<1%
Petroleum	43,440	<1%
Pumped Storage	1,691	<1%
TOTAL	102,397,711	

CGS February 2026 Outage

4. CGS was unexpectedly shut down at 2:49 a.m. PT on February 12, 2026. CGS alerted the Nuclear Regulatory Commission (NRC) of the outage by 9:25 a.m. ET on the same day.[5] The outage occurred due to an issue with the cooling system that supports the reactor's recirculation pumps.[6] CGS came back online at approximately 3:30 p.m. on February 18,

[1] NW Power and Conservation Council. Power Generation Map. https://www.nwcouncil.org/energy/energy-topics/power-supply/map-of-power-generation-in-the-northwest/
[2] EIA-923 Power Plant Operations Report (released: 9/18/2025). Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923). https://www.eia.gov/electricity/data/state/
[3] https://www.seattletimes.com/seattle-news/environment/northwests-only-commercial-nuclear-power-plant-back-online-after-repair/
[4] EIA-923 Power Plant Operations Report (released: 9/18/2025). Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923). https://www.eia.gov/electricity/data/state/
[5] https://www.nrc.gov/reading-rm/doc-collections/event-status/event/2026/20260213en
[6] https://www.energy-northwest.com/news-releases/columbia-generating-station-back-online/

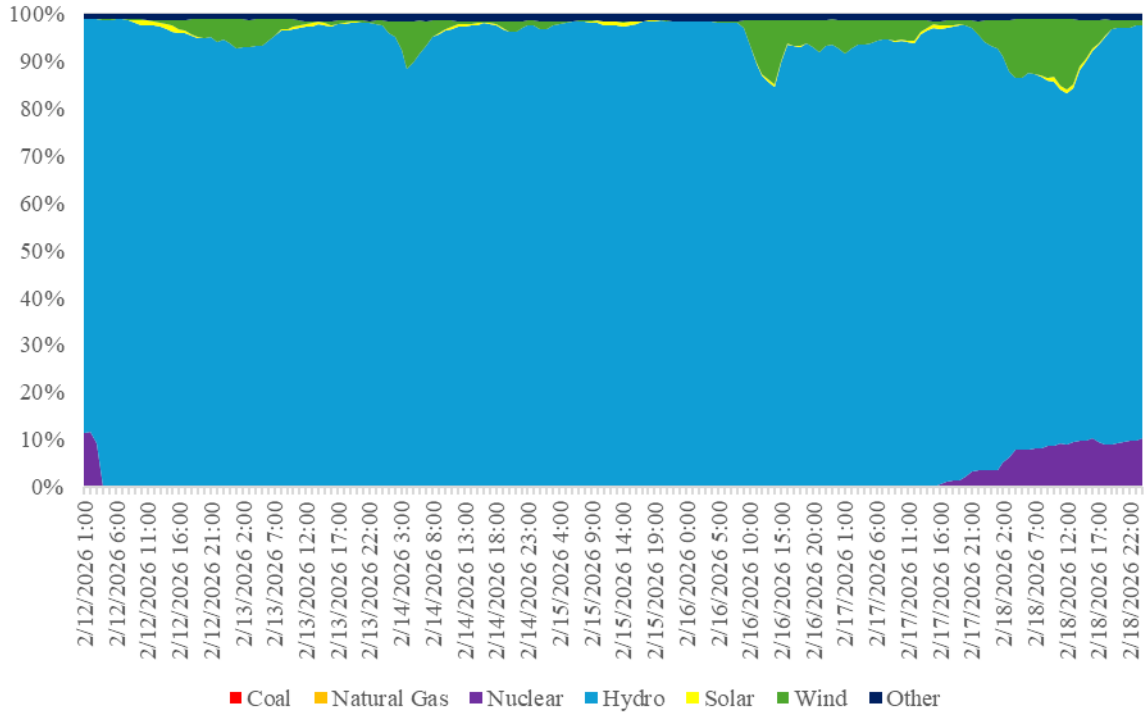
ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

2026.[7] CGS had not experienced an unplanned outage since May 2018,[8] although CGS has planned outages roughly every two years for refueling.[9]

5. During the time of the CGS outage, BPA's balancing area experienced a peak hourly demand of 9,634 MW.[10] The Pacific Northwest is a winter peaking system, with BPA's Balancing Authority Area annual load ranging from 10,500 to over 11,500 MW.[11]

CGS Outage Did Not Cause Blackouts and Did Not Require Operation of TransAlta Centralia

Figure 1: Hourly Generation Resource Mix in BPA Balancing Authority[12]



[7] https://www.energy-northwest.com/news-releases/columbia-generating-station-back-online/

[8] https://www.seattletimes.com/seattle-news/environment/northwests-only-commercial-nuclear-power-plant-back-online-after-repair/; https://www.nwpb.org/nw-news/2018-05-20/tri-cities-nuclear-reactor-columbia-generating-station-shuts-down-in-unplanned-event

[9] https://www.energy-northwest.com/energy-projects/columbia-generating-station/refueling-outages/

[10] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48

[11] BPA: Balancing Authority Load & Total VER Generation) 5. Data for BPA Balancing Authority Total Load, Wind Gen, Wind Forecast, Solar Gen, Solar Forecast, Hydro, Thermal, and Net Interchange: (Note-New data format for 2022 and beyond implemented 08/17/22)

[12] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

6. Despite the 6-day outage, there were no blackouts during the time when CGS was offline.[13] According to EIA's Hourly Electric Grid Monitor data, Bonneville Power Administration (BPA) maintained net generation greater than net demand through the entire duration of the unplanned outage. According to EIA Hourly Grid Monitor data, the BPA region covered the loss of CGS power, which was providing approximately 10% of total supply right before the outage, with hydropower and wind resources.[14] At no point did BPA require coal generation to balance the grid and serve load.[15]

DATED this 13 day of April 2026, in Seattle, Washington.

CALLAHAN MORIYASU

[13] https://www.nwpb.org/local/2026-02-17/columbia-generating-station-to-come-back-online-this-week
[14] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48
[15] Id.

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

EXHIBIT 105

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-18

DECLARATION OF MENGCHIU LIM
IN SUPPORT OF
MOTION TO INTERVENE, REQUEST FOR REHEARING,
AND MOTION TO STAY BY STATE OF WASHINGTON

I, MengChiu Lim, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

1. I am now and at all times mentioned have been a permanent resident of the United States, over the age of 18 years, competent to make this declaration, and I make this declaration from my own personal knowledge and judgment.

2. I am currently employed by the Washington State Department of Ecology (Ecology) as the senior regulatory and engineering specialist lead for the Air Quality Program. I have worked in this position for almost three years. Before becoming a senior regulatory and engineering specialist, I worked as the Prevention of Significant Deterioration (PSD) Program Lead at Ecology. I held that position for four years.

3. I have a Bachelor of Science degree in Civil Engineering from the University of South Alabama, and I am a registered Professional Engineer in Washington State.

4. In my current position I am the lead engineer for PSD permitting and serve as the senior engineer to support technical and regulatory projects in the Air Quality Program.

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

5. As part of these duties, I assess applications for PSD permits. PSD permits are a prerequisite to construction of certain new sources of air pollution or major modifications at existing facilities that could increase air pollution.

6. Ecology received a PSD permit application from TransAlta on December 24, 2025. Ex. 105-1 (TransAlta PSD Permit Application).

7. On January 23, 2026, Ecology issued an incompleteness letter, asking TransAlta to propose a volatile organic compound (VOC) emission limit for Boiler #2 and provide supporting justification. Ex. 105-2 (Ecology Incompleteness Letter).

8. On March 10, 2026, TransAlta sent Ecology a response with the requested information, which Ecology will review for completeness. Ex. 105-3 (TransAlta Incompleteness Letter Response).

9. Ecology anticipates that, depending on the outcome of the review and public comment process, it will issue a PSD permit for TransAlta's natural gas conversion in late summer or early fall of 2026. TransAlta cannot begin actual construction until after Ecology issues its PSD permit and finishes the State Environmental Policy Act (SEPA) review, and it receives the necessary permits from the Southwest Clean Air Agency. Ecology is the lead SEPA agency and anticipates that the SEPA process will be completed before it issues the PSD permit, depending on the outcome of the public comment periods.

DATED this 14 day of April, in 2026, Washington.

MENGCHIU LIM

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

EXHIBIT 105-1

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

TransAlta Centralia Generation, LLC

Lewis County, Washington

December 2025

Prepared for

TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

Prepared by



828 Great Northern Blvd, Suite 300
Helena, MT 59601

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table of Contents

1.0 INTRODUCTION 1-1

1.1 Regulatory Overview 1-2

1.2 Application Overview 1-1

1.2.1 Application Organization 1-1

1.2.2 Application Contacts 1-1

2.0 PROJECT DESCRIPTION 2-2

2.1 Project Summary 2-2

2.2 Description of Major Equipment 2-2

2.2.1 Unit #2 2-2

2.2.2 Auxiliary Boiler 2-2

2.2.3 Unit #2 Cooling Towers 2-3

2.2.4 Water Bath Heaters 2-3

2.3 Emissions Estimates 2-3

2.3.1 Unit #2 2-3

2.3.2 Auxiliary Boiler and Water Bath Heaters 2-4

2.3.3 Emissions for CTG Operations 2-4

3.0 REGULATORY APPLICABILITY EVALUATION 3-1

3.1 PSD/NSR 3-1

3.1.1 New Major Stationary Source Test 3-1

3.1.2 Major Modification Test 3-3

3.1.3 Control Technology Review 3-4

3.1.4 Ambient Air Quality Analysis Requirements 3-4

3.1.5 Source Impact Analysis 3-5

3.1.6 Additional Impact Analyses 3-5

3.2 New Source Performance Standards (40 CFR Part 60) 3-6

3.2.1 40 CFR 60, Subpart A – General Provisions 3-6

3.2.2 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units 3-6

3.2.3 40 CFR 60, Subpart Db – Standards of Performance for Electric Utility Steam Generating Units 3-8

3.2.4 40 CFR 60, Subpart Dc – Standards of Performance for Electric Utility Steam Generating Units 3-8

3.2.5 40 CFR 60, Subpart TTTT – Greenhouse Gas Emissions for New or Modified Electric Generating Units 3-9

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.2.6 40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units 3-9
3.3 National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63) 3-9
3.3.1 40 CFR 61 – National Emission Standards for Hazardous Air Pollutants (NESHAPs) 3-9
3.3.2 40 CFR 63 – NESHAPs for Source Categories 3-10
3.4 TItle V 3-11
3.5 Acid Rain Program 3-11
3.6 Greenhouse Gas Reporting Rule 3-11
3.7 State of Washington Agency Regulations 3-12
3.7.1 Air Pollution Control Authority – Powers and Duties 3-12
3.7.2 Construction of Proposed New Contaminant Sources 3-12
3.7.3 Prevention of Significant Deterioration 3-12
3.7.4 Controls for New Sources of Toxic Air Pollutants 3-12
3.7.5 Ambient Air Quality Standards 3-13
3.8 Southwest Clean Air Agency Regulations 3-13
3.8.1 General Standards for Maximum Emissions 3-13
3.8.2 Emissions Standards for Combustion and Incineration Units 3-13
3.8.3 Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants 3-14
3.8.4 Startup and Shutdown 3-14
3.8.5 Operating Permit Fees 3-14
3.8.6 Records, Monitoring and Reporting 3-14
3.8.7 Air Discharge Permit Applications 3-14
3.8.8 Application Review Process for Stationary Sources (New Source Review) 3-15
3.8.9 Requirements for New Sources in Attainment or Nonclassifiable Areas (if PSD) 3-15
4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS 4-1
4.1 Top-Down BACT Approach and Analysis Organization 4-2
4.1.1 Step 1 - Identify All Control Technologies 4-2
4.1.2 Step 2 - Eliminate Technically Infeasible Options 4-2
4.1.3 Step 3 - Rank Remaining Technologies by Control Effectiveness 4-2
4.1.4 Step 4 - Evaluate Most Effective Controls and Document Results 4-2
4.1.5 Step 5 - Select BACT 4-3
4.2 Unit #2 4-3
4.2.1 Step 1 – Identify All Control Technologies 4-3

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

4.2.2 Step 2 – Eliminate Technically Infeasible Options 4-4
4.2.3 Step 3 – Rank Remaining Technologies by Control Effectiveness 4-4
4.2.4 Step 4 – Evaluate Most Effective Controls and Document Results 4-4
4.2.5 Step 5 – Select BACT 4-5
4.3 Auxiliary Boiler 4-5
4.3.1 Step 1 – Identify All Control Technologies 4-5
4.3.2 Step 2 – Eliminate Technically Infeasible Options 4-5
4.3.3 Step 3 – Rank Remaining Technologies by Control Effectiveness 4-5
4.3.4 Step 4 – Evaluate Most Effective Controls and Document Results 4-6
4.3.5 Step 5 – Select BACT 4-6
4.4 Water Bath Heaters 4-6
5.0 AMBIENT AIR IMPACT DEMONSTRATION/RESULTS 5-1
5.1 Introduction 5-1
5.2 Load Analysis 5-1
5.3 Secondary Pollutant Assessment 5-1
5.3.1 Secondary $PM_{2.5}$ Assessment 5-1
5.3.2 O_3 Ambient Impact Assessment 5-2
5.4 Project Impacts Compared to the SILS 5-2
5.5 NAAQS Analysis and Results 5-3
6.0 REFERENCES 6-1

List of Tables

Table 2-1. Summary of Project Emissions 2-4
Table 3-1. Summary of Permitted Potential Emissions and Applicable Regulatory Thresholds 3-4
Table 3-2. State of Washington Potentially Applicable Regulations 3-12
Table 3-3. SWCAA Potentially Applicable Regulations 3-13
Table 4-1. Unit #2 VOC Control Technology Options and Costs, Ranked by Control Efficiency 4-4
Table 4-2. Auxiliary Boiler VOC Control Technology Options, Ranked by Control Efficiency 4-5
Table 5-1. SILs Analysis Results 5-3
Table 5-2. NAAQS Analysis Results 5-3

List of Figures

Figure 1-1. Facility Location Map 1-1
Figure 2-1. Unit #2 Process Flow Diagram 2-2

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

List of Appendices

Appendix A: WDOE Application Forms
Appendix B: Emission Calculations
Appendix C: Supporting Documentation for the Regulatory Analysis
Appendix D: Supporting Documentation for BACT Analysis
Appendix E: Air Dispersion Modeling Analysis
Appendix F: Visibility Modeling Analysis

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Acronyms/Abbreviations

ADP	Air Discharge Permit
AP-42	U.S. Environmental Protection Agency Compilation of Air Pollutant Emission Factors
ASIL	Acceptable source impact level
BACT	Best available control technology
BART	Best available retrofit technology
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EU	Emissions unit
FCAA	Federal Clean Air Act
FR	Federal Register
GHG	Greenhouse gas
gr/dscf	Grains per dry standard cubic foot
HAP	Hazardous air pollutant
lb/MMBtu	Pounds per million British thermal units
lb	Pounds
lb/hr	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
N_2O	Nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAA	Nonattainment Area

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

NNSR	Nonattainment Area New Source Review
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
PM	Particulate matter
PM_{10}	Particulate matter with a diameter of 10 micrometers or less
$PM_{2.5}$	Particulate matter with a diameter of 2.5 micrometers or less
PSD	Prevention of Significant Deterioration
PTE	Potential to emit
RCW	Revised Code of Washington
SO_2	Sulfur dioxide
SWCAA	Southwest Clean Air Agency
TAPs	Toxic Air Pollutants
tpy	Tons per year
VOC	Volatile organic compounds
WDOE	Washington Department of Ecology
WAC	Washington Administrative Code

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (TransAlta) operates the Centralia electrical generation facility at the Big Hanaford site in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at 7,500 million British Thermal Units per hour (MMBtu/hr). Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity. The Facility operates under Southwest Clean Air (SWCAA) Operating Permit #SW-98-8-R5. The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 Code of Federal Regulations, CFR, 81.327) for all pollutants.

TransAlta proposes to modify the existing Unit #2 coal-fired electrical generation facility from coal to natural gas combustion, referred to as a coal to gas (CTG) conversion (the Project). Unit #2 will cease using coal as a fuel source in December 2025. Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy for use by the customer. Unit #2 will be operated at a maximum 59% capacity factor, which may entail operating at maximum heat input for fewer hours or operating at a lower megawatt (MW) output for extended hours. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the Project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW). TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

The framework and function of the boiler will remain unchanged after the conversion, including most of the existing boiler parts related to absorbing the heat from the combustion of fuels and converting it to superheated steam. To change the fuels, the burners in each corner of the boiler will be modified to create the proper mixture of natural gas and air for proper combustion.

Unit #2 will use low NO_x burners (LNB), separated overfire air (SOFA), a combustion optimization system (COS), and flue gas recirculation (FGR) to minimize formation of oxides of nitrogen (NO_x) during combustion. Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) will be controlled using good combustion practices. Particulate matter (PM), sulfur dioxide (SO_2)[1], and sulfuric acid mist (H_2SO_4) emissions will be controlled through good combustion practices and the use of clean-burning pipeline-quality natural gas.

The Project will also require replacing the existing oil-fired auxiliary boiler with a new natural gas-fired unit and replacing the existing Unit #2 cooling towers. New units associated with the modification will include two natural gas-fired water bath heaters (10 MMBtu/hr each).

[1] Unit #2 is currently equipped with PM and SO_2 controls associated with coal combustion. These controls will be removed as a part of the conversion to natural gas combustion as natural gas produces far less of both pollutants than prior operations.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

1.1 Regulatory Overview

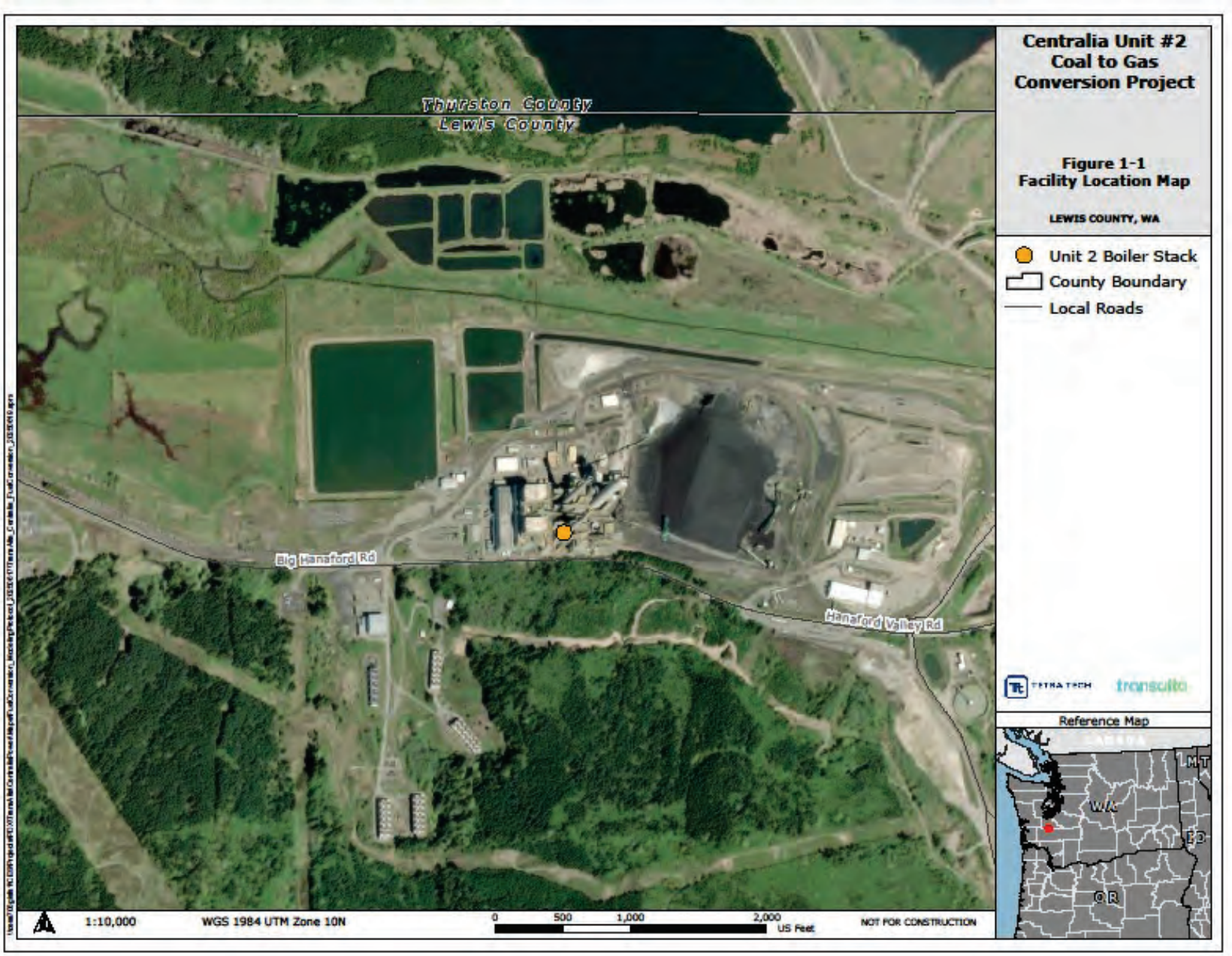
Air emissions from the proposed Project primarily consist of combustion products from Unit #2. Because Lewis County is designated as unclassifiable/attainment with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants and the Facility is a major stationary source under the Prevention of Significant Deterioration (PSD) permitting program, a PSD applicability analysis is required. Based on that analysis, VOC emissions trigger PSD review requirements by exceeding its major modification significant emissions rate (SER). The PSD program is implemented by the Washington Department of Ecology (WDOE). TransAlta is submitting this PSD permit application to WDOE to address Project VOC emissions.

The other criteria pollutants do not trigger PSD and will be subject to the minor source air discharge permit (ADP) program as administered by SWCAA. Those pollutants include[2]: NO_x, CO, PM with a diameter equal to or less than 10 micrometers (PM_{10}), and PM with a diameter equal to or less than 2.5 micrometers ($PM_{2.5}$), SO_2, and H_2SO_4. A separate ADP application will be submitted to SWCAA. The required air toxics analysis will also be submitted to SWCAA because that analysis is within the jurisdiction of the minor source permitting program.

The Project will be in compliance with federal, state, and SWCAA air quality requirements, including the NAAQS, WDOE AAQS, and WDOE's air toxics requirements, as well as all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP).

[2] Greenhouse gas (GHG) emissions also fall below the SER and therefore do not trigger PSD. In addition, they are not subject to minor source permitting because GHGs are not regulated at the minor source permitting level.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD



Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

1.2 Application Overview

1.2.1 Application Organization

This permit application is divided into six sections. Section 1 provides an overview of the Project and regulatory requirements. Section 2 provides a detailed description of the Project, including calculated emissions. Section 3 provides a more detailed discussion of applicable regulations. Section 4 provides the Best Available Control Technology (BACT) emissions control technology evaluations for the applicable criteria pollutants. Section 5 provides air quality modeling analyses demonstrating compliance with the NAAQS. Section 6 provides a list of references.

The WDOE PSD application form is included as Appendix A. Emission calculation spreadsheets providing supporting calculations for the application are provided in Appendix B. Appendix C presents supporting documents for the regulatory analysis. Appendix D presents supporting documents for the BACT analysis. Appendix E provides the air dispersion modeling analysis including detailed emissions and stack parameter data used in the dispersion modeling, a schematic Project layout diagram and Building Profile Input Program (BPIP) model output, detailed model results, and a summary of the Project's Modeling Protocol, submitted to WDOE and SWCAA on September 26, 2025. Similarly, the visibility modeling demonstration and supporting analysis is provided in Appendix F.

1.2.2 Application Contacts

To facilitate agency review of this application, individuals familiar with the Facility and this application are identified below.

Conrad Wieclaw
TransAlta Corporation
Phone: 360-807-8093
e-mail: Conrad_Wieclaw@transalta.com

Debbie Skibicki
Tetra Tech, Inc.
Phone: 406-437-9830
e-mail: debbie.skibicki@tetratech.com

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

2.0 PROJECT DESCRIPTION

2.1 Project Summary

TransAlta operates the Centralia electrical generation facility at the Big Hanaford site, in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at a nominal heat input rate of 7,500 MMBtu/hr. Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity.

The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 CFR 81.327) for all pollutants.

2.2 Description of Major Equipment

2.2.1 Unit #2

The updated Unit #2, rated at 723 megawatts (MW, net), will generate steam from natural gas combustion. The steam produced will be converted to electrical energy in the existing steam turbine. The electrical energy will be sold for use by the customer. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. Unit #2 will be operated up to (and limited to) a maximum 59% capacity factor. Figure 2-1 provides the process flow diagram for Unit #2 operations.

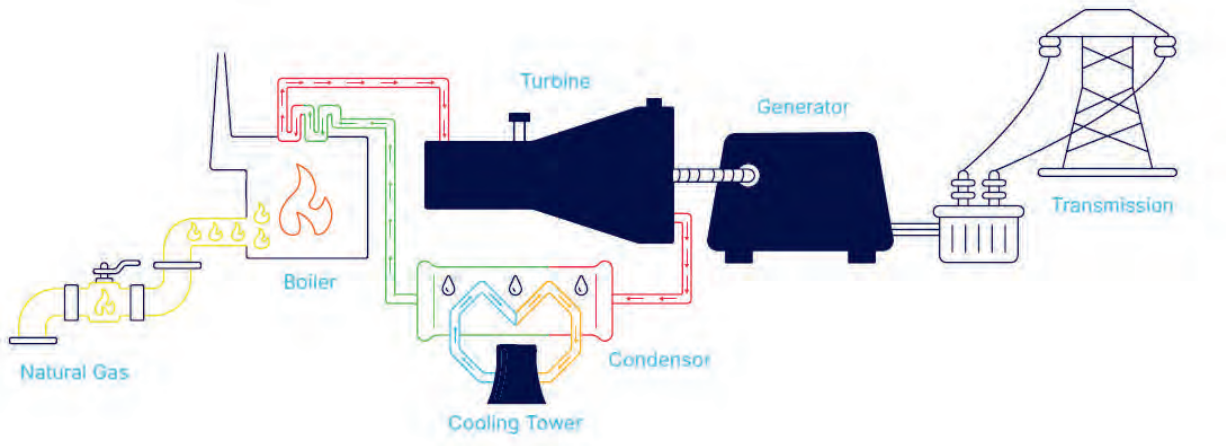


Figure 2-1. Unit #2 Process Flow Diagram

2.2.2 Auxiliary Boiler

The new auxiliary boiler will use natural gas, operating as needed to keep Unit #2 warm during periods of shutdown and to provide steam to Unit #2 during startup and shutdown. It also provides building heat in cold weather periods when Unit #2 is offline. The auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr and will be limited to 1,300 hours of total operation per year.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

2.2.3 Unit #2 Cooling Towers

The Project includes the replacement of the Unit #2 Cooling Towers with new units. Cooling towers cool the circulating water from the Unit #2 steam turbine. This cooling will be accomplished by means of two twelve-cell mechanical draft low-mist wet cooling tower, operating only when Unit #2 operates (emissions are calculated using 8,760 hours per year of operation to be conservative). A mechanical draft cooling tower will cool the circulating water by spraying the warm circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water will be entrained in this air flow; this water entrainment is called drift. Each cell of the cooling tower will be equipped with drift eliminators that are typically located above the water sprays to remove the vast majority of the entrained water droplets and return them to the fill. However, a small fraction of these droplets will escape into the fan discharge and be released to the atmosphere. The droplets that are released to the atmosphere contain dissolved solids that form particulates when the droplets evaporate and, therefore, are a source of particulate matter emissions ($PM/PM_{10}/PM_{2.5}$). The water contains no additives or cleaning products that would contribute to or produce emissions.

2.2.4 Water Bath Heaters

The Project includes two water bath heaters to heat the natural gas fuel for combustion in Unit #2 and the auxiliary boiler. Water bath heaters indirectly heat incoming gas to keep the temperature above the point where water or hydrocarbon hydrates could condense in the gas, particularly as pressure drops to meet Unit #2 and the auxiliary boiler fuel input requirements. The proposed water bath heaters are each rated at 10 MMBtu/hr and are planned to operate 8,760 hours per year.

2.3 Emissions Estimates

Emissions from the Project primarily consist of products of combustion from Unit #2. The auxiliary boiler, cooling towers, and water bath heaters are smaller sources of overall Project emissions.

2.3.1 Unit #2

As previously mentioned, Unit #2 emissions are evaluated at a maximum 59% capacity factor at full load burning natural gas. Unit #2 is also assessed at minimum stable generation (190 MW). This load scenario does not impact the potential emissions calculations but is evaluated in the air dispersion modeling analysis to ensure compliance with standards at those specific exhaust parameters. VOC emissions rates are based on the anticipated vendor guarantee of 0.003 lb/MMBtu across generation profiles. VOC emissions rates are expected to follow fuel combustion rates during startup and shutdown operations (as in when the amount of fuel combusted decreases, so do the emission rates of VOC).

Beyond the combustion emissions, when Unit #2 is shutdown, there may be need for the venting of natural gas remaining in the boiler. Those emissions, listed under “shutdown methane venting” are calculated based on a worst-case 50 shutdowns per year and the anticipated venting rate. TransAlta will employ best fuel management practices to minimize the methane venting including slowing of

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

fuel into Unit #2 if shutdown is anticipated and firing Unit #2 longer into shutdown to combust excess fuel. Methane is not a regulated pollutant under this action or under the ADP regulatory process, but the information and emissions are provided for administrative completeness.

2.3.2 Auxiliary Boiler and Water Bath Heaters

The VOC emissions for the auxiliary boiler and the water bath heater are based on AP-42, Chapter 1.4 (External Combustion Sources - Natural Gas Combustion) emission factors.

2.3.3 Emissions for CTG Operations

The emissions for the proposed operations are provided in the table below. Importantly, the "Total CTG Project Emissions" line does not take into account that the Project's emissions (except VOC) will be significantly less than the baseline of coal-fired emissions. Unit #2 CTG emissions are based on operations being limited to the annual 59% capacity factor. The overall net decrease in emissions is provided in the applicability analysis in Section 3.1. All pollutants are included for completeness.

Table 2-1. Summary of Project Emissions

TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NO_x[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.01**	**2,291,727**

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.0 REGULATORY APPLICABILITY EVALUATION

This section contains an analysis of the applicability of federal and state air quality regulations to the Facility. The specific regulations and programs that are included in this review include:

- PSD/New Source Review (NSR);
- New Source Performance Standards (NSPS);
- Federal National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Title V Operating Permits;
- Federal Acid Rain Permits;
- Federal Greenhouse Gas (GHG) Reporting Requirements;
- Other WDOE requirements; and
- Other SWCAA requirements.

3.1 PSD/NSR

In accordance with 40 CFR 52.21(2), PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area[3] and is an existing major stationary source as defined in 40 CFR 52.21(b)(1)[4]. Both the “new major stationary source” and “major modification of any existing major stationary source” analyses are provided below, in addition to information on PSD requirements for this application.

3.1.1 New Major Stationary Source Test

The Centralia Plant is a major stationary source that is currently operating. Because the Facility would need to temporarily cease operations to allow for the conversion of Unit #2 and construction of the new associated emissions units, WDOE requested discussing the United States Environmental Protection Agency’s (EPA) “Reactivation Policy.” The “Guidance on Washington State’s Prevention of Significant Deterioration Permitting Program” (WDOE PSD Guidance), Section 2.2.2.1.3 – Restarting Emissions Units states that “when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways.” Those ways include the amount of time the facility was out of operation, the reason for the shutdown, statements by the owner or operator regarding intent, and others.

WDOE PSD Guidance under “Reactivation Policy,” states the following:

> *“EPA’s policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.[5] Reactivating a “permanently” shut down source*

[3] *See, e.g.,* Air Quality Modeling Results: Levels of Sulfur Dioxide in the Ambient Air Around TransAlta Centralia Generation Power Plant (WDOE 2017).
[4] The Centralia Plant is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input which emits 100 tons per year or more of any regulated NSR pollutant.
[5] WDOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

> *makes the source a new source under current PSD guidance. A source shutting down for more than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

The WDOE PSD Guidance also states:

> *"Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[6] and is the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in its discussions with Lewis County; SWCAA, the regional air permitting authority, and WDOE in addition to vendors, customers, interested stakeholders, etc. has specifically and repeatedly expressed their intent to continue operation of the Centralia Plant as a natural gas generation resource. These plans were developed well before the anticipated end of coal combustion and will continue to build in depth and intensity through the startup of operations.

As mentioned in the WDOE PSD Guidance document, as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated

[6] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear – the Unit #2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of continued operation. This intent, along with additional EPA criteria support the conclusion that the limited shutdown of Unit #2 was "not intended to be permanent." Thus, Unit #2 is not a new source under these circumstances. The criteria are individually evaluated in a Reactivation Analysis provided in Appendix C – Supporting Documents for Regulatory Analysis.[7]

3.1.2 Major Modification Test

Pursuant to 40 CFR 52.21(b)(1), a modification of an existing major stationary source is considered a "major modification" if it results in a "a significant emissions increase… of a regulated NSR pollutant… and a significant net emissions increase of that pollutant from the major stationary source." The analysis of emissions increases is divided into two steps as described in the WDOE PSD Guidance. The first step evaluates if the change will result in a significant emissions increase of any regulated PSD pollutant, based on the application of federal regulations. If there is a significant increase in a PSD pollutant, the second step determines whether the change will result in a significant net emissions increase.

An emissions increase is significant if the increase is greater than one or more of the SERs listed in 40 CFR § 52.21(b)(23). Although EPA guidance states that both increases and decreases resulting from a project shall be accounted for under Step 1 of the applicability process,[8] also known as project emissions accounting or project netting, such accounting is explicitly prohibited under WDOE PSD Guidance. Therefore, consistent with WDOE's policy, no project netting was undertaken when calculating the baseline emissions for Unit #2.

An emissions increase is calculated by subtracting the baseline actual emissions from the projected actual emissions. Baseline emissions for any existing electric utility steam generating unit are "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project" as described in 40 CFR 52.21(b)(48). Because Unit #2 is the emissions unit being modified, the 24-month baseline period was considered specifically for that unit. The baseline period (2022-2023) chosen by TransAlta meets the criteria of being within the 5-year period immediately preceding when actual construction is anticipated to begin (2026-2027) and being representative of normal operations. Other units/equipment associated with the coal combustion operations being retired or removed are not

[7] On September 18, 2025, EPA issued an updated guidance memorandum on the "Reactivation Policy." In that guidance, EPA states that it "will no longer apply any form of the Reactivation Policy in its NSR permitting determinations and enforcement proceedings, or in its oversight of state, local and tribal air permitting programs." EPA also stated that it "will continue to apply the modification provisions of the NSR program to shut down sources in accordance with the CAA and applicable EPA regulations." The modification analysis for this project is provided in Section 3.1.2 - Major Modification Test.

[8] See discussion: Federal Register :: Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Regulations Related To Project Emissions Accounting; Withdrawal of Proposed Rule, July 21, 2025.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

included in this analysis as reductions. The projected actual emissions for Unit #2 are the future potential emissions associated with operating at the maximum 59% capacity factor.

Table 3-1 provides the 2022-2023 baseline for Unit #2 (as reported to and accepted by SWCAA for the criteria pollutants and EPA's GHG Reporting System for the GHGs) and the future potential emissions for Unit #2 and the other Project emissions units[9]. VOC is the only pollutant that triggers PSD requirements in the first step. Because no project netting is undertaken, the second step is unnecessary and the conclusion in the first step is confirmed. The other pollutants are included for completeness in the analysis.

Table 3-1. Summary of Permitted Potential Emissions and Applicable Regulatory Thresholds

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
	(tons per year)									
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.00	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the combustion optimization process.

As previously discussed, VOC is the only pollutant that triggers PSD requirements.

3.1.3 Control Technology Review

Pursuant to 40 CFR 52.21(j), major sources conducting a major modification must meet the BACT standard for all pollutants for which PSD permitting is required. The BACT analysis for the Project VOC emissions is included in Section 4.0.

3.1.4 Ambient Air Quality Analysis Requirements

In accordance with the requirements of 40 CFR 52.21(m), a PSD permit application must contain an analysis of existing ambient air quality data in the affected area for all regulated pollutants for which PSD permitting is required and a demonstration that the Project will not cause or contribute to a violation of the NAAQS or PSD increments. The definition of existing air quality can be satisfied by air

[9] The above described approach is also consistent with WDOE PSD Guidance. Baseline emissions for Unit #2 were evaluated as described/required in Section 2.2.2.2.2 of that guidance. In addition, the project emissions increase (also referred to as the "Step 1" increase) was calculated pursuant to Section 2.2.2.2.4. No netting was contemplated or requested, therefore the requirements in Section 2.2.2.2.5 - "Calculate the net emissions increase" were not applicable.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

measurements from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. To fulfill the pre-construction monitoring requirement for PSD without conducting on-site monitoring a source may either:

- Justify that data collected from existing monitoring sites are conservatively representative of the air quality in the vicinity of the Project site; or
- Demonstrate that the Project is less than the de minimis monitoring concentrations established by EPA in 40 CFR 52.21(i)(5).

There are no NAAQS or PSD increments for VOC emissions, and therefore ozone (O_3, for which VOC is a precursor) is the pollutant which represents the potential trigger for an ambient impact analysis and the gathering of pre-construction ambient monitoring data. However, in the note associated with 40 CFR 52.21(i)(5)(i)(F), the regulations state that "No de minimis air quality level is provided for ozone. However, any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of ambient air quality data." As shown in Table 3-1, the proposed Project would result in an increase in VOC emissions of 58.83 tons per year, so it will meet the criteria for exemption from the ambient impacts analysis and preconstruction monitoring requirements for O_3.

Nevertheless, as previously mentioned, an ambient air quality demonstration for all NAAQS pollutants (including O_3) is summarized in Section 5.0 and provided in detail in Appendix E.

3.1.5 Source Impact Analysis

Pursuant to 40 CFR 52.21(k), a source impact analysis is required to be performed when a proposed project triggers PSD review for at least one regulated pollutant for which NAAQS exist. An increment consumption analysis is also required for projects that will increase emissions of pollutants with PSD increments have been established for Class I and Class II areas: PM_{10}, $PM_{2.5}$, SO_2, CO and NO_2. As described in Section 3.1, the Project triggers PSD review for VOCs only and no VOC-specific source impact analysis is required.

3.1.6 Additional Impact Analyses

Pursuant to 40 CFR 52.21(o), the additional impact analyses include an analysis of impairment to visibility (expanded upon in 40 CFR 52.21(p)), soils and vegetation, and the growth-related impacts associated with the source or modification, as described below.

3.1.6.1 Visibility Analysis

PSD Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. According to 40 CFR 52.21(p), sources with emissions that may affect a Class I area may be required to demonstrate that modifications subject to PSD review will not cause or contribute to an exceedance of any PSD Class I increment or adversely affect certain air quality related (AQRVs, including visibility and acid deposition). As previously noted, there are no PSD increments or air quality related values for VOC. As the Project is only subject to PSD review for VOC, no Class I area impacts analysis is required under this section.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

However, a visibility analysis was required for this Project under other requirements, specifically because "any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled" (as described in the Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant, (WDOE, July 2020)). The CALPUFF visibility analysis is included in Appendix F.

3.1.6.2 Soils and Vegetation

The PSD program also provides an assessment of the potential impacts that a project subject to PSD will have on soils and vegetation. Such assessments are often conducted by comparing predicted maximum offsite ambient impacts determined by air dispersion modeling for secondary NAAQS. Secondary NAAQS define maximum concentration levels for protecting soils, vegetation, wildlife, and other aspects of public welfare. Secondary NAAQS thresholds have been established for NO_2, PM_{10}, $PM_{2.5}$, and O_3 but not for VOC. Because the Project is only subject to PSD review for VOC, a soils and vegetation impacts assessment is not required. However, as noted above, the ambient air quality demonstration for all NAAQS pollutants (including O_3 for both the primary and secondary standards) is included in Appendix E.

3.1.6.3 Growth Related Impacts

A qualitative evaluation of the general commercial, residential, industrial, and other potential growth that may be associated with the proposed Project was conducted. As Unit #2 is currently operating as an electrical generation unit combusting coal, its operations in the same function combusting natural gas are not anticipated to change employment patterns at the Centralia Plant or its vicinity. Therefore, secondary growth is not anticipated as a result of the Project.

3.2 New Source Performance Standards (40 CFR Part 60)

New Source Performance Standards (NSPS) are technology-based standards applicable to new and modified stationary sources. NSPS standards were delegated to SWCAA on July 1, 2015 (and incorporated by reference pursuant to SWCAA 400-115). Several NSPS subparts apply to the Project. The following is a description of the applicable subparts, potentially applicable subparts, and the Facility's compliance with these standards.

3.2.1 40 CFR 60, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include notification of the start of construction, notification of the start of operation, performance emissions testing, monitoring, recordkeeping, and reporting.

3.2.2 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units

40 CFR 60, Subpart Da applies to each electric utility steam generating unit capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (alone or in combination with any other fuel); for which construction, modification, or reconstruction is commenced after September 18, 1978. Unit #2

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

has the capability of combusting more than 250 MMBtu/hr of fossil fuel; it is rated at 7,500 MMBtu/hr. The original Unit #2 was not subject to Subpart Da as construction occurred prior to the applicability date of September 18, 1978 (construction was authorized in 1969, with operation commencing in August of 1971). However, the Unit #2 CTG conversion will happen after the applicability date and must be evaluated with respect to triggering modification or reconstruction under this subpart.

Per 40 CFR 60.14, modification is considered as any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies under Section 111 of the Federal Clean Air Act. Further, no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change. None of the maximum hourly emissions rates as described above would increase for Unit #2 with the proposed change, therefore, modification under this subpart is not triggered[10].

Per 40 CFR 60.15, reconstruction means the replacement of components of an existing facility to such an extent that:

1. The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
2. It is technologically and economically feasible to meet the applicable standards set forth in this part.

The analysis focuses on the first criteria. EPA has clarified the term “fixed capital cost” to mean “the capital needed to provide all the depreciable components and is intended to include such things as the costs of engineering, purchase, and installation of major process equipment, contractors’ fees, instrumentation...” In addition, per EPA guidance dated February 28, 2008, “Costs outside of the affected facility, such as the building, air pollution control, testing, and monitoring equipment, site preparation, removal of the old turbine, and contingency costs should not be included” in the fixed capital cost for this calculation.

As a basis, the United States Energy Information Administration (EIA) publishes capital costs associated with constructing new electrical generation facilities categorized by fuel, nominal capacity in MW, and general technology[11]. Because natural gas-fired boilers are not a listed technology[12], the

[10] The permitted NOx emissions rate was 0.21 lb/MMBtu over a 30-operating day average for Units 1 and 2 operating on coal. The proposed NOx emissions rate following full operations of the emissions control suite is 0.083 lb/MMBtu, also on a 30-operating day average for Unit #2, far below the previously permitted NOx limit, both in that form and if converted to a lb/hr value. In addition, as discussed with SWCAA, compliance testing performed in 2021 showed VOC test results of 0.0125 lb/MMBtu for Unit #2. VOC test results of that magnitude were also reported in 2019 for Unit #2. This short-term emissions rate exceeds the proposed natural gas VOC rate of 0.003 lb/MMBtu, both in that form and if converted to a lb/hr value.

[11] US EIA - Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies.

[12] Listed technologies for natural gas combustion include variations on simple and combined cycle combustion turbines in both simple and advanced configurations with and without carbon capture technology.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

closest similar unit type would be an "ultra-critical coal plant without carbon capture." A nominal 650 MW plant today of that type at $4,103/kilowatt-net would cost $2.67 billion in 2023$ (all the dollar amounts that follow are in 2023$). In the EIA analysis, the boiler cost component is shown at $395.7 million. The total equipment cost is $997.5 million; therefore, the boiler accounts for 40% of the total equipment cost shown. Applying that percentage to the total plant cost provides a boiler cost including labor; engineering, procurement, and construction (EPC) fees; contingency and owners costs of $1.07 billion. The Unit #2 boiler scope including those same components is currently estimated at approximately $173 million, equating to approximately 17% of the replacement cost. Both of those cost estimates include site preparation and contingency costs, which are calculated as a percent of the capital costs. As a result, the overall percent of replacement cost is valid without pulling out those items specifically. Therefore, Unit #2 boiler scope falls below the 50% reconstruction standard under 40 CFR 60.15(1).

Given that neither modification per §60.14 nor reconstruction per §60.15 is triggered for Subpart Da, the Unit #2 conversion is not subject to this standard.

3.2.3 40 CFR 60, Subpart Db – Standards of Performance for Electric Utility Steam Generating Units

Subpart Db applies to steam generating units with a maximum input capacity greater than 100 MMBtu/hr and less than 250 MMBtu/hr that commences construction, modification, or reconstruction after June 19, 1984. The auxiliary boiler has a maximum input capacity of 149.13 MMBtu/hr, would commence construction after the applicability date and is, therefore, subject to the standard. For a subject unit combusting natural gas with a low heat release rate, such as the auxiliary boiler, NO_x emissions are limited to 0.10 lb/MMBtu. The auxiliary boiler has a proposed NOx emissions rate of 12 parts per million, which equates to approximately 0.015 lb/MMBtu on a rolling 30-day average. As such, the Facility meets the applicable emission limits under Subpart Db. The standard also requires a continuous emissions monitoring system (CEMS) for monitoring NO_x emissions. A continuous opacity monitoring system (COMS) is not required pursuant to §60.48b(j)(2) if records are maintained for the sulfur content of the natural gas burned (due to the low sulfur content and particulate emissions from natural gas). Similarly, as described in §60.42b(k)(2), units burning natural gas are also exempt from SO_2 limitations and monitoring requirements.

3.2.4 40 CFR 60, Subpart Dc – Standards of Performance for Electric Utility Steam Generating Units

Subpart Dc is applicable to steam generating units with a maximum heat input capacity greater than or equal to 10 MMBtu/hr and less than 100 MMBtu/hr for which construction, modification, or reconstruction is commenced after June 9, 1989. The natural gas-fired water bath heaters heat a water bath, have a maximum heat input of 10 MMBtu/hr, and would commence construction after the applicability date; therefore, the water bath heaters are subject to this standard. The standard requires initial notifications at the start of construction and at initial start-up. In addition, records must be maintained regarding the amount of fuel burned on a monthly basis. No emission or operating limits are imposed by this standard on natural gas-fired units.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.2.5 40 CFR 60, Subpart TTTT – Greenhouse Gas Emissions for New or Modified Electric Generating Units

Subpart TTTT is applicable to electric utility generating units (EGUs) with a heat input greater than 250 MMBtu/hr of fossil fuel that serve a generator capable of selling greater than 25 MW of electricity to a utility power distribution system that commences construction on or after January 8, 2014, or commenced reconstruction or modification on or after June 8, 2014. As an existing unit, Unit #2 is not currently subject to Subpart TTTT. Therefore, the requirements of Subpart TTTT can only become applicable if Unit #2 undergoes a modification or reconstruction, as defined under 40 CFR 60.14 and 60.15.

As previously discussed under Section 3.2.2 (Subpart Da), neither modification nor reconstruction has been triggered for Unit #2, therefore, Subpart TTTT is not applicable to this Project.

3.2.6 40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa applies to any steam generating unit or Integrated Gasification Combined Cycle (IGCC) unit that combusts coal and that commences modification after May 23, 2023, in addition to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in §60.5509a(a)(1) and (2).

As previously discussed under Section 3.2.2 (Subpart Da), Unit #2 will not combust coal after December 31, 2025, and thus would not be subject to the first set of applicability requirements. In addition, no stationary combustion turbines exist onsite, and none are currently planned for the site. Therefore, Subpart TTTTa is not applicable to this Project.

3.3 National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)

The Clean Air Act of 1970 required EPA to identify hazardous air pollutants (HAPs) and promulgate standards for each HAP. Between 1971 and 1990, EPA identified and published standards for eight HAPs (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride) under 40 CFR 61. The Clean Air Act Amendments of 1990 added 189 HAPs to Section 112 of the Clean Air Act and gave EPA a specific schedule to issue final standards on sources of these HAPs. EPA has published more than 100 standards under 40 CFR 63 in accordance with the Clean Air Act Amendments of 1990. The 40 CFR 61 standards are pollutant-specific, whereas the 40 CFR 63 standards are source category-specific.

3.3.1 40 CFR 61 – National Emission Standards for Hazardous Air Pollutants (NESHAPs)

3.3.1.1 40 CFR 61, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 61 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

requirements of Subpart A also apply. These obligations include compliance requirements; performance-based emissions testing; and monitoring, recordkeeping, and reporting requirements.

3.3.1.2 40 CFR 61, Subpart M – General Provisions

Subpart M shall apply, but not be limited to, the demolition and/or renovation of regulated asbestos containing material. The Facility will comply with this standard as applicable during the conversion of Unit #2 and other affected units. Further, the Facility shall comply with the provisions of SWCAA 476 "Standards for Asbestos Control, Demolition and Renovation" when conducting any renovation, demolition, or asbestos storage activities at the facility.

3.3.2 40 CFR 63 – NESHAPs for Source Categories

3.3.2.1 40 CFR 63, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 63 is also subject to the general provisions under Subpart A. Because the Facility is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include compliance dates; operation and maintenance requirements; startup, shutdown, and malfunction plans; performance emissions testing; and monitoring, recordkeeping, and reporting. The Facility has complied with and will continue to comply with the applicable requirements, performance testing, recordkeeping, and reporting outlined in Subpart A.

3.3.2.2 40 CFR 63, Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR 63, Subpart DDDDD applies to industrial, commercial, or institutional boilers or process heaters as described in §63.7485 located at a major source of HAP emissions. The Facility is a major source of HAPs. Pursuant to §63.7499 and to §63.7575, Unit #2 following CTG conversion falls into the Gas 1 subcategory of “new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.” As described by Table 3 of Subpart DDDDD, the Facility must conduct a tune-up of Unit #2 annually as specified in §63.7540. In addition, Unit #2 (as an existing unit at a major source of HAPs) must have a one-time energy assessment performed by a qualified energy assessor. The specifics of that energy assessment are described in Table 3, Section 4 of Subpart DDDDD. The auxiliary boiler falls into the Gas 1 category *with* a continuous oxygen trim system and will be subject to an every-five-year tune-up requirement. The water bath heaters will be categorized when their detailed specifications are available.

3.3.2.3 40 CFR 63, Subpart UUUUU – NESHAPs for Coal- and Oil-Fired Electric Utility Steam Generating Units

40 CFR 63, Subpart UUUUU, also known as the Mercury Air Toxics Standard (MATS), previously applied to Unit #2 in the existing EGU category (specifically the “coal-fired unit not low rank virgin coal” subcategory). Pursuant to §63.9981, MATS only applies to coal-fired or oil fired EGUs as they are defined in §63.10042 of that subpart. Unit #2 firing only natural gas would no longer be subject to MATS.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.4 Title V

Title V of the Federal Clean Air Act Amendments of 1990 sets forth operating permit requirements that apply to major sources as defined in the statute. The Air Operating Permit program is authorized under the procedures established in WAC 173-401. Several alternative criteria establish major source status, but the primary criteria that most often trigger applicability are:

- The facility's potential to emit any pollutant from a stationary point source is greater than 100 tpy.
- The facility's potential to emit any single listed HAP is greater than 10 tpy, or its potential to emit all HAPs combined is greater than 25 tpy.

The Centralia Plant meets the above criteria and currently holds SWCAA Air Operating Permit #SW98-8-R5, issued on October 14, 2019. The Air Operating Permit renewal application was submitted on March 15, 2023, and determined to be administratively complete on September 18, 2024, in accordance with WAC 173-401-710(1) and WAC 173-401-500.

Pursuant to WAC 173-401-500(3)(c), TransAlta will apply for a Title V modification within 12 months after commencing operation to address the requested modification.

3.5 Acid Rain Program

Unit #2 meets the definition of an affected Phase II "utility unit" under the Acid Rain Program pursuant to 40 CFR 72.6 because it is a fossil-fuel fired combustion device used to generate electricity for sale, and it serves a generator that exceeds 25 MW in capacity. Unit #2 has an existing Phase II Acid Rain Permit that has been incorporated into Centralia Plant's 40 CFR Part 70 Air Operating Permit #SW98-8-R5.

Under the Acid Rain Rule, the Centralia Plant is required to hold allowances equivalent to annual NOx and SO_2 emissions. The Centralia Plant will amend the existing Phase II Acid Rain Permit to address the conversion of Unit #2 to natural gas combustion, that application is incorporated into the ADP application submitted to SWCAA.

With respect to the monitoring requirements, NO_x CEMS remain a requirement under 40 CFR 75.10 and 75.12. Pursuant to 40 CFR 75.11(d), SO_2 monitoring for gas-fired units shall elect the use of SO_2 CEMS or the fuel monitoring and sulfur in fuel measurement allowed for under 40 CFR 75, Appendix D. Pursuant to 40 CFR 75.14(c) and (d), gas-fired units are exempt from the opacity monitoring provisions of Subpart 75.

3.6 Greenhouse Gas Reporting Rule

The GHG Reporting Rule (40 CFR Part 98 – Mandatory GHG Reporting) requires the reporting of specific GHG emissions by direct GHG emitters, as well as upstream indirect sources such as fossil fuel suppliers and manufacturers of heavy-duty and off-road vehicles and engines.

Electricity generation units that report CO_2 mass emissions year-round through 40 CFR Part 75 are subject to GHG reporting pursuant to 40 CFR 98.2(a)(1) and are subject to the specific provisions of 40 CFR Part 98, Subpart C. Therefore, the Centralia Plant has been reporting GHG emissions under this

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

program since the 2010 reporting year and the Project will continue to comply with these requirements.

3.7 State of Washington Agency Regulations

In addition to regulations already discussed in preceding sections, state air regulations that pertain to the Facility are listed in Table 3-2. The rules are addressed individually in the following sections as they pertain to the Facility.

Table 3-2. State of Washington Potentially Applicable Regulations

Rule	Description
RCW 70A.15.2040	Air Pollution Control Authority – Powers and Duties
RCW 70A.15.2210	Construction of Proposed New Contaminant Sources
WAC 173-400-700, et seq.	Prevention of Significant Deterioration
WAC 173-460	Controls for New Sources of Toxic Air Pollutants
WAC 173-476	Ambient Air Quality Standards

3.7.1 Air Pollution Control Authority – Powers and Duties

The Revised Code of Washington (RCW) 70A.15.2040 (previously codified at RCW 70.94.141) delineates and empowers activated air pollution control authorities to develop plans for the prevention, abatement and control of air pollution within its jurisdiction. An air pollution control authority may issue such orders as may be necessary to effectuate the purposes of the Washington Clean Air Act and enforce the same by all appropriate administrative and judicial proceedings subject to the rights of appeal as provided in state law.

3.7.2 Construction of Proposed New Contaminant Sources

RCW 70A.15.2210 (previously codified at RCW 70.94.152) provides for the inclusion of conditions of operation as are reasonably necessary to assure the maintenance of compliance with the applicable ordinances, resolutions, rules and regulations when issuing Air Discharge Permits for installation and establishment of air contaminant sources.

3.7.3 Prevention of Significant Deterioration

WAC 173-400-700 through 750 includes the requirements that incorporate the federal PSD program by reference and provide authority for WDOE's State Implementation Plan (SIP)-approved PSD program. As previously mentioned, PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area and is an existing major stationary source as defined in 40 CFR 52.21(b)(1). This application is being submitted to WDOE to address the PSD requirements for the Facility with respect to VOC.

3.7.4 Controls for New Sources of Toxic Air Pollutants

WAC 173-460 establishes requirements for toxic air pollutants (TAPs, listed in WAC 173-460-150) including BACT for TAPs, TAPs emissions quantifications, and analysis of human health and safety

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

protection. The TAPs emissions calculations, BACT analysis, and compliance analysis are included in the ADP permit application.

3.7.5 Ambient Air Quality Standards

WAC 173-476 establishes maximum acceptable levels in the ambient air for PM/PM_{10}/$PM_{2.5}$, lead, SO_2, NO_x, O_3, and CO. The air quality of the Project site is classified as "Better than National Standards" or unclassifiable/attainment of the NAAQS for criteria pollutants (40 CFR 81.327). The air dispersion modeling analysis/demonstration of compliance with these standards is provided in Section 5.0 and Appendix E.

3.8 Southwest Clean Air Agency Regulations

In addition to regulations already discussed in preceding sections, local agency air regulations that will pertain to the Project are listed in Table 3-3. The rules are addressed individually in the following sections as they pertain to the facility.

Table 3-3. SWCAA Potentially Applicable Regulations

Rule	Description
SWCAA 400-040	General Standards for Maximum Emissions
SWCAA 400-050	Emissions Standards for Combustion and Incineration Units
SWCAA 400-076	Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants
SWCAA 400-081	Startup and Shutdown
SWCAA 400-103	Operating Permit Fees
SWCAA 400-105	Records, Monitoring and Reporting
SWCAA 400-109	Air Discharge Permit Applications
SWCAA 400-110	Application Review Process for Stationary Sources (New Source Review)
SWCAA 400-113	Requirements for New Sources in Attainment or Nonclassifiable Areas

3.8.1 General Standards for Maximum Emissions

SWCAA 400-040 requires all new and existing sources and emission units to meet certain performance standards with respect to Reasonably Available Control Technology (RACT), visible emissions, fallout, fugitive emissions, odors, emissions detrimental to persons or property, sulfur dioxide, concealment and masking, and fugitive dust. The Facility will continue to comply with all the applicable requirements and general provisions in SWCAA 400-040.

3.8.2 Emissions Standards for Combustion and Incineration Units

SWCAA 400-050 requires that no person shall cause or permit the emission of particulate material from any combustion or incineration unit in excess of 0.23 grams per dry cubic meter (0.1 grains per dry standard cubic foot, gr/dscf) of exhaust gas at standard conditions. This standard is applicable to Unit #2, the auxiliary boiler, and the water bath heaters. All of the listed units have calculated PM values of less than 0.004 gr/dscf, in compliance with this standard.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.8.3 Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants

SWCAA 400-076 provides that if an ADP application is required under both SWCAA 400 and Chapter 173-460 WAC, then the applications shall be combined. TransAlta includes the required air toxics review and analysis in the ADP application, Sections 4.0 (for the air toxics BACT) and Section 5.0 (for the impact analysis).

3.8.4 Startup and Shutdown

SWCAA 400-081 requires the consideration of any physical and operational constraints on the ability of a "stationary source" or source category to comply with the applicable technology-based standard during startup or shutdown. In addition, modeling of the emissions must consider any increase in allowable emissions under startup or shutdown conditions authorized by an emission limitation or other operating parameter adopted under this rule section. Startup and shutdown impacts were evaluated and studied for Unit #2. Based on those evaluations, VOC emissions are anticipated to be consistent across a lb/MMBtu basis, as when the amount of fuel combusted decreases, the emissions associated with fuel combustion would also decrease. Therefore, the VOC emissions expressed in lb/MMBtu account for the startup and shutdown emissions without further need for clarification or allowances. The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations. Further discussion on the non-VOC startup and shutdown emissions for Unit #2 is included in the ADP application submitted to SWCAA.

3.8.5 Operating Permit Fees

SWCAA 400-103 requires the owner or operator of all "stationary sources" required to obtain an Operating Permit under 40 CFR Part 70, Chapter 173-401 WAC or RCW 70A.15.2260, to pay an annual fee as specified in this section, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the Operating Permit Program, including the fees associated with review and acting on applications and the associated application analyses. TransAlta has and will continue to pay the appropriate operating fees to SWCAA.

3.8.6 Records, Monitoring and Reporting

SWCAA 400-105 provides for all Title V stationary sources to maintain records of type and quantity of emissions, applicable emission limitations, operating limitations, and control measures. TransAlta currently maintains those calculations, records, and compliance demonstrations associated with its current Title V Operating Permit and will continue to do so under the requested permit modification.

3.8.7 Air Discharge Permit Applications

SWCAA 400-109 requires an ADP application for new construction or installation; modification, alteration or replacement of existing process or control equipment; and review of case-by-case control technology determinations (e.g., BACT) among other activities. The Project would trigger an ADP application for all of the above activities. The ADP application will be submitted with the appropriate fees as detailed in the Consolidated Fee Schedule established in accordance with SWCAA 400-098.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.8.8 Application Review Process for Stationary Sources (New Source Review)

SWCAA 400-110 includes provisions for application completeness. Applications shall include a demonstration that all applicable emissions standards have been met (including BACT, NSPS, NESHAPs, etc.), compliance with the ambient air quality standards, and PSD applicability review. TransAlta has included the required analyses in this Section 3.1.

3.8.9 Requirements for New Sources in Attainment or Nonclassifiable Areas (if PSD)

SWCAA 400-113 provides requirements for new or modified PSD sources in an attainment or unclassifiable area. Those requirements include compliance with emissions standards, BACT, allowable impact levels, PSD applicability, TAPs review, and visibility analyses. The Project will meet the requirements described with respect to the PSD pollutant under review - VOC.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The Washington Clean Air Act requires all new sources and modifications which increase emissions to employ BACT. As previously discussed, VOC is the only pollutant triggering major source permitting under PSD pursuant to 40 CFR 52.21(j) (as referenced by WAC 173-400-710(1)). BACT is defined under 40 CFR 52.21(b)(12) as:

> *"an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, 62, and 63. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results*."

EPA has consistently interpreted the BACT requirement as containing two core criteria: (i) the BACT analysis must include consideration of the most stringent available technologies, (i.e., those that provide the "maximum degree of emissions reduction"; and (ii) any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable.

EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached based on the environmental, energy, and economic impacts. WDOE requires the "top-down" approach for PSD BACT, which is described in more detail below.

This section provides the basis of the analysis prior to evaluating BACT for the new or modified sources. The sources subject to BACT for VOC include Unit #2, the auxiliary boiler, and water bath heaters.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

4.1 Top-Down BACT Approach and Analysis Organization

The “top down” general procedures are outlined in the *New Source Review Workshop Manual*, Office of Air Quality Planning and Standards, EPA, Draft - October 1990. The Manual was written for use in BACT analyses under the PSD or federal NSR program. The methodology described in the manual consists of five basic steps, which are described below.

4.1.1 Step 1 - Identify All Control Technologies

In a complete BACT analysis, the first step is to identify all “available” control options for the emissions unit being evaluated. “Available” control options are air pollution control technologies or techniques with a practical potential for application to the emissions unit and regulated pollutant being evaluated.

4.1.2 Step 2 - Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in the first step is evaluated with respect to source-specific factors. A demonstration of technical infeasibility must be clearly documented and exhibit – based on physical, chemical, and/or engineering principles – that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are eliminated from further consideration. Note that the NSR Manual (at page B-17) states, “a source is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique or control technology. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type.”

4.1.3 Step 3 - Rank Remaining Technologies by Control Effectiveness

Available control technology options deemed technically feasible are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollutant removal value or lowest pollutant emission limit is considered the "top" control option.

4.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

The fourth step is to consider the directly associated energy, environmental, and economic impacts of the most stringent control option ascertained. Both beneficial and adverse impacts are discussed and quantified where possible.

Energy impact analyses estimate direct energy impacts of the control alternatives in units of energy consumption. Environmental impact analyses consider effects of unregulated air pollutants or non-air impacts such as liquid, solid, or hazardous waste disposal and whether they would justify selection of an alternative control option. Economic impact analyses assess costs associated with installation and operation of the various BACT alternatives.

As a guide in determining excessive control costs, alternative control systems are compared in terms of certain cost-effectiveness ratios. These ratios include the following:

- Ratio of total control costs to total investment costs;
- Cost per unit of pollution removed (for example, dollars per ton);

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

- Unit production costs (for example, costs per unit of product); and
- Cost per dollar of total sales.

If energy, environmental, or economic impacts show the top control option to be infeasible, then the next most stringent alternative becomes the new top control option and is similarly evaluated. This process continues until the top control technology under consideration cannot be eliminated due to any source-specific energy, environmental, or economic impact(s).

4.1.5 Step 5 - Select BACT

The last step in evaluating BACT is to propose the most effective control option that remains after eliminating all non-viable options as part of Step 4.

4.2 Unit #2

Unit #2 currently operates as a coal-fired EGU using diesel as a startup fuel. Following the ceasing of coal combustion at the end of 2025, the Project proposes converting Unit #2 to generate electricity from natural gas. Unit #2 proposed to operate at a maximum capacity factor of 59%. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the Project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW).

Natural gas combustion produces NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and VOC. VOC is the only pollutant subject to PSD, therefore, for this application, VOC is the pollutant subject to review under this major source BACT process. GHGs, expressed as CO_{2e}, are also produced but are not subject to BACT review as the modification of Unit #2 does not trigger PSD permitting for GHG emissions. Unit #2 is evaluated as an existing source undergoing a fuel conversion; potentially applicable NSPS requirements (specifically Subpart Da) do not apply as neither modification nor reconstruction are being triggered. Therefore, new similar source installations are not comparable with respect to control technology requirements.

However, to provide a more comprehensive outline of the potential options, a review of EPA's Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emissions Rate (LAER) Clearinghouse (collectively, RBLC) was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 11.310 – Utility and Large Industrial Sized Boilers/Furnaces > 250 MMBtu/hr, Natural Gas Fired). Twelve boilers were identified between June 2017 and July 2024, all of which were smaller than Unit #2, with the largest being two units: 1,100 MMBtu/hr and 1,200 MMBtu/hr in size. In addition, nine known coal to gas converted utility boilers (units very consistent with Unit #2) were also surveyed. That information is available in Appendix D and will be discussed as applicable.

4.2.1 Step 1 – Identify All Control Technologies

The rate of VOC emissions from boilers and furnaces depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde, hexane, and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

As previously discussed, a review of the RBLC natural gas fired boilers and known converted units was conducted to identify control technology alternatives for Unit #2. The VOC control technologies for those units included good combustion practices, clean fuel usage (i.e., natural gas), compliance with 40 CFR 63, Subpart DDDDD (the Boiler MACT), and following manufacturer specifications for startup and shutdown events. Those options can be summarized as good combustion practices. Optimized boiler operation minimizes emissions overall.

The search results did not identify any listings in which the use of catalytic oxidation was found to represent BACT; however, it is an option used for VOC control in natural gas combustion. A catalytic oxidation system is a post-combustion technology that removes VOC from the exhaust gas of a combustion source via incineration. VOC is oxidized/converted to H_2O and CO_2 in a combustion chamber in which the VOC-containing waste stream is burned. Since the inlet waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature via auxiliary fuel. In the catalytic incinerator a catalyst is used to increase the rate of the combustion reaction, allowing the combustion to occur at lower temperatures. Because the catalytic process operates at a lower temperature than the thermal process, less auxiliary fuel may be required in the catalytic process to preheat the waste gas.

4.2.2 Step 2 – Eliminate Technically Infeasible Options

Both good combustion practices (including boiler tune-ups per the Boiler MACT) and catalytic oxidation are feasible options. Technology-specific impacts are discussed in Step 4.

4.2.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-1. Unit #2 VOC Control Technology Options and Costs, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)	Annual Cost (in 2023$)	Cost Effectiveness ($ per ton)
1	Catalytic Oxidation	99%	0.00003	$47,947,931	$838,100
2	Good combustion practices	Base case	0.003	N/A	N/A

The default control efficiency in EPA's Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers (December 2024) is 99% and remains so in this analysis to be conservative. Economic impacts associated with catalytic oxidation were compared using estimated annualized capital, operating, and maintenance costs[13] evaluated using that EPA spreadsheet.

4.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

A potential adverse environmental impact for a catalytic oxidizer results from the handling of the spent catalyst. Many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under RCRA. Costs for the installation of catalytic oxidation are exorbitantly high

[13] Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

at $838,100 per ton of VOC removed. This falls far beyond generally acceptable dollar per ton costs for pollution control for PSD or minor source BACT analyses.

4.2.5 Step 5 – Select BACT

Given the consistency of requiring no add-on control for all the boilers surveyed and the cost associated with the installation and operation of catalytic oxidation, TransAlta proposes that the use of good combustion practices (including compliance with the Boiler MACT) coupled with the use of pipeline quality natural gas is VOC BACT for Unit #2.

4.3 Auxiliary Boiler

The auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr, will be limited to 1,300 hours of total operation per year to support startups and shutdowns for Unit #2, and will fire only natural gas as fuel. A search of EPA's RBLC was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 12.310 –Industrial Sized Boilers/Furnaces between 100 and 250 MMBtu/hr, Natural Gas Fired, see Appendix D). However, the units surveyed did not indicate the same limited use as with the auxiliary boiler.

As described above with respect to Unit #2, the rate of VOC emissions from boilers and furnaces, depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air.

4.3.1 Step 1 – Identify All Control Technologies

A review of the RBLC was conducted to identify control technology alternatives for the auxiliary boiler. The VOC control technologies for those units included good combustion practices for all units and catalytic oxidation for one within the search window.

4.3.2 Step 2 – Eliminate Technically Infeasible Options

Both good combustion practices and catalytic oxidation would be technically feasible.

4.3.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-2. Auxiliary Boiler VOC Control Technology Options, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)
1	Catalytic Oxidation	99%	0.00005
2	Good combustion practices	Base case	0.005

The default control efficiency in EPA's Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers (December 2024) is 99% and remains so in this analysis to be conservative. Using that spreadsheet, annual cost (in 2023$) was estimated at $569,479 per year with a cost effectiveness of $1,231,413 per ton based on the anticipated emissions rate at the limited hours of operation (0.48 tpy of VOC).

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

4.3.4 Step 4 – Evaluate Most Effective Controls and Document Results

Catalytic oxidation would be the most effective control. However, based on the limited use of the auxiliary boiler and the minimal emissions generated, no add-on control technology would be economically feasible. Good combustion practices, including compliance with the Boiler MACT, is a consistent VOC BACT requirement for boilers in this size range.

4.3.5 Step 5 – Select BACT

TransAlta proposes that the use of good combustion practices, including compliance with the Boiler MACT, coupled with the use of pipeline quality natural gas as VOC BACT for the auxiliary boiler.

4.4 Water Bath Heaters

Combustion emissions (including VOC) are generated from the two water bath heaters. The units are small natural gas-fired heaters, rated at 10 MMBtu/hr each. Due to their size, the pollutants generated are small with the VOC emission rates for each heater at 0.22 tpy. Based on the small size of the heater and the minimal emissions generated, no add-on control technology would be economically feasible. VOC emissions will be minimized through the combustion of pipeline quality natural gas and by following good combustion practices for these units. Therefore, TransAlta proposes the use of pipeline quality natural gas and good combustion practices (including compliance with the Boiler MACT) as BACT for VOCs.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

5.0 AMBIENT AIR IMPACT DEMONSTRATION/RESULTS

The following is a summary of the air dispersion modeling analysis/ambient air quality impact demonstration and results. Detailed information on the modeling methodology is provided in Appendix E.

5.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NOx and SO_2 emissions are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NOx and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of ultra-low sulfur diesel fuel in Unit #2. Unit #2 will now only fire natural gas.

5.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2, and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios/loads are provided in Appendix E, Attachment A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS, and toxics modeling analyses.

5.3 Secondary Pollutant Assessment

5.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Appendix E, Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

(24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NOx and SO_2 based on EPA photochemical modeling. The most representative EPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NOx emissions and 500 tpy for SO_2 precursor emissions. Section 4.3.1 of Appendix E provides the calculations used to estimate the Project-only secondary $PM_{2.5}$ impacts.

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

5.3.2 O_3 Ambient Impact Assessment

Chemical transformation of NOx and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Appendix E, Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing EPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NOx and VOC based on the EPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the EPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NOx emissions and 500 tpy of VOC precursor emissions. Section 4.3.2 of Appendix E provides the calculations used to estimate the Project-only secondary O_3 impacts

5.4 Project Impacts Compared to the SILS

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 5-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 5-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 5-1. SILs Analysis Results

Pollutant	Averaging Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	98.49[c]	7.5
	Annual	H1H	1.14[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	1.86[c]	1.2
	Annual	H1H (5-year average)	0.26[c]	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	5.66 ppb[c]	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

5.5 NAAQS Analysis and Results

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Appendix E, Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and representative ambient background concentrations (as described in Appendix E, Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 5-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 5-2 are shown in contour plots provided in Attachment B of Appendix E.

Table 5-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117. 98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

6.0 REFERENCES

EIA 2024. Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. Available online at: Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies

EPA 1990. New Source Review Workshop Manual (Draft). Available online at: NSR Workshop Manual (Draft October 1990)

EPA 2024. Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers. Available online at: Incinerators and Oxidizers Calculation Spreadsheet (note: updated December 2024)

EPA 2024. Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. Available online at: AP-42: Compilation of Air Emissions Factors from Stationary Sources | US EPA

EPA 2025. RACT/BACT/LAER Clearinghouse (RBLC). Available online at: Clean Air Technology Center | US EPA

WDOE 2017. Guidance on Washington State's Prevention of Significant Deterioration Permitting Program. Available online at: Guidance on Washington State's Prevention of Significant Deterioration Permitting Program

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX A: WDOE APPLICATION FORMS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

EARLY PLANNING

In order to develop an appropriate application, the source should engage in an early planning process to assess the needs of the facility. An opportunity for a pre-application meeting with ecology is available to any potential applicant. We recommend meeting with Ecology before preparing a PSD application.

INSTRUCTIONS

Use this form for all projects in Washington that are subject to the Prevention of Significant Deterioration (PSD) Program. If you want Ecology to determine whether your project is subject to the PSD Program, submit a Request for a PSD Program Applicability Determination form (ECY 070-413).

Fill out the front and back of this form. Attach a check for the initial fee and mail the form and your application to:

Department of Ecology
Cashiering Unit
PO Box 47611
Olympia, WA 98504-7611

For Fiscal Office Use Only:
001-NSR-216-0299-000404

Check the box to indicate what you are submitting for review.

Project	Initial Fee
☑ For new major stationary source or major modification. The initial fee covers 158 hours of review	$18,802
PSD Permit Revision	
☐ Administrative permit amendment. The initial fee covers 20 hours of review Please contact PSD section for eligibility prior to submittal.	$2,380
☐ All other PSD permit revision. The initial fee covers 40 hours of review	$4,760
Other Actions	
☐ Permit extension. This is a flat fee.	$625
☐ Plant-wide applicability emission limit: establish limit. The initial fee covers 158 hours of review	$18,802
☐ Plant-wide applicability emission limit: all other requests. Other requests may include increasing a limit, renewing a limit, or processing an expired limit. The initial fee covers 79 hours of review. Contact PSD section prior to submittal.	$9,401

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

Read each statement, and then check the box next to it to acknowledge what you have read.

The initial fee you submit may not cover the cost of processing your application. Ecology will track the number of hours spent on your project. If the number of hours exceeds the number of hours included in your initial fee, Ecology will send you a bill for that extra time.

Ecology will bill you $119 per hour for each hour worked beyond the initial hours.

You must pay the bill before we will issue your permit or finalize an action or decision.

Note:

An additional fee does not apply when a request to establish a plant-wide applicability limit is part of an application covered by the new project, all other permit revisions, or major modification fees on this form

FOR MORE INFORMATION

MengChiu Lim
Department of Ecology Air Quality Program
Engineering and Permitting Section Ecology Headquarters Office

PO Box 47600
Olympia, WA 98504-7600
Phone: 360-407-6812
email: mengchiu.lim@ecy.wa.gov

The Department of Ecology is committed to providing people with disabilities access to information and services by meeting or exceeding the requirements of the Americans with Disabilities Act (ADA), Section 504 and 508 of the Rehabilitation Act, and Washington State Policy #188.

To request an ADA accommodation, contact Ecology by phone at 360-407-6800 or email at melanie.forster@ecy.wa.gov. For Washington Relay Service or TTY call 711 or 877-833-6341. Visit Ecology's website for more information.

If you need this document in a format for the visually impaired, call the Air Quality Program at 360-407-6800. Persons with hearing loss can call 711 for Washington Relay Service. Persons with a speech disability can call 877-833-6341.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

I. Project, Facility, and Company Information

a. Project Name: Centralia Coal to Gas Conv

b. Facility Name: TransAlta Centralia Plant

c. Facility Street Address: 913 Big Hanaford Road, Centralia, WA 98531

d. Company Legal Name: TransAlta Centralia Generat

II. Application Contact Information

Project Manager:

a. Name: Conrad Wieclaw

b. Mailing Address: 913 Big Hanaford Road, Ce

c. Phone Number: (360)807-8093

d. Email: Conrad_Wieclaw@transalta

Project Consultant

If you hired a consultant to prepare the application (or materials), check this box and provide the required information.

e. Consultant name: Debbie Skibicki

f. Consultant Mailing Address: 828 Great Northern Ave, Ste 300, Helena, MT 59601

g. Consultant Phone Number: (406)437-9830

h. Email: debbie.skibicki@tetratech.c

Project Billing Contact

Ecology will send the Project Manager the bills if there are any

☐ If the Project Billing Contact is different from the Project Manager, check this box and provide the required information.

i. Name, Title:

j. Mailing Address:

k. Phone Number:

l. Email:

III. Responsible Official Certification

Responsible Official Signature

I certify, based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate, and complete.

Printed name: Conrad Wieclaw Title: Engineering and Environmental Manager

Signature: Signed by: Conrad Wieclaw 130F85AFA0D74B4... Date: 23 December 2025 | 2:20 PM MST

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

IV. Project Information

For any project involves new major stationary source or major modification of any existing major stationary source, the application shall include the following information, but not limited to:

a. **Project description.** Please provide a detail description of the project and identify the scope of the project. This shall include the new and modified emission unit (s), and other affected existing unit (s) of the project. The project description shall also include an aggregation analysis to evaluate if nominally-separate projects occurring at the source shall be treated as a single project from PSD standpoint. The baseline actual emissions and the projected actual emissions.
b. **Project emission increase.** Please provide a summary of the project emission increase. Please also provide a detail emission increase estimation for each unit included as part of the project.
c. **BACT evaluation.** The applicant shall use top-down procedure similar to that in the draft 1990 NSR workshop manual. Startup/shutdown shall be evaluated as part of the BACT analysis. For economy impact analysis as part of the evaluation, the application shall show the assumptions made and provide the supporting information for the assumptions.
d. **Impact review.** For impact analysis purpose, actual emissions is based on the last two years of emissions that is representative of normal source operation.
e. **State Environmental Policy Act (SEPA) Determination.** If SEPA review is completed, please include a copy of the final SEPA checklist and SEPA determination. If SEPA review has not been conducted, please identify the agency reviewing SEPA and provide a copy of the final SEPA checklist and SEPA determination before Ecology issues your permit

Ecology has developed a PSD guidance that can be helpful when conducting PSD applicability analysis. The guidance can be found at https://fortress.wa.gov/ecy/publications/SummaryPages/1702014.html.

Please note that the applicant shall provide a copy of PSD application to each of the following agencies:

a. U.S. Department of the Interior—National Park Service
b. U.S. Department of Agriculture—U.S. Forest Service
c. The permitting authority with authority over the source under Chapter 173-401 WAC
d. EPA

Ecology recommends that the applicant provides an electronic copy of the application to Ecology's PSD program.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX B: EMISSIONS CALCULATIONS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
					(tons per year)					
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.000	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

[2]Baseline emissions compiled from emission inventories submitted to and approved by Southwest Clean Air Agency for the respective reporting years with the exception of CO_{2e}. CO_{2e} emissions were compiled from 40 CFR 98, Greenhouse Gas Reporting summaries.

[3]Pursuant to 40 CFR 52.21(b)(i), "For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project." TransAlta chose the 2022-2023 period for Unit 2.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.009**	**2,291,727**

*The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Unit 2 Full load, 59% capacity operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	7,500.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	59%	
Hours of Operation =	5,168	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	5,168	hr/yr
NG Fuel Usage =	35,016.26	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	8.25E+02	2,131.97
CO	0.15	lb/MMBtu	TA Predicted	1.13E+03	2,907.23
VOC	0.003	lb/MMBtu	TA Predicted	2.25E+01	58.14
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	5.39E+00	13.92
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	8.24E-02	0.21
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	8.77E+05	2,267,195
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+01	42.73
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+00	4.27
CO_{2e}	-			8.78E+05	2,269,524
HAPs	See table below				33.06

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (7500 MMBtu/hr) = 51.4905 lbs/hr
PM Emissions (tons/yr) = (51.4905 lbs/hr) x (5168.4 hrs/yr) / (2000 lbs/ton) = 133.062 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	4.2E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	2.8E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	4.2E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	3.7E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	2.1E-02
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	5.3E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	4.9E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	1.3E+00
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	3.2E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	1.1E-02
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	3.0E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	8.8E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	6.0E-02
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	3.5E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	2.1E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.9E-02
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	2.0E-02
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	4.4E-03
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	1.5E-03
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	1.5E-02
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	8.8E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	6.7E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	4.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	3.7E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	4.2E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	4.0E-02
				NG HAPs Total	**33.06**

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9
https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response
https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf
https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Unit 2 190 MW operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	2,529.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	100%	
Hours of Operation =	8,760	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	8,760	hr/yr
NG Fuel Usage =	20,012.68	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	2.78E+02	1,218.47
CO	0.15	lb/MMBtu	Proposed BACT	3.79E+02	1,661.55
VOC	0.003	lb/MMBtu	TA Predicted	7.59E+00	33.23
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	1.82E+00	7.96
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	2.78E-02	0.12
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	2.96E+05	1,295,760
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E+00	24.42
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E-01	2.44
CO_{2e}	-			2.96E+05	1,297,091
HAPs	See table below				18.90

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (2529 MMBtu/hr) = 17.3626 lbs/hr
PM Emissions (tons/yr) = (17.3626 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 76.048 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP		--	
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.4E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.6E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.4E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	2.1E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.2E-02
Ethylbenzene	100-41-4	HAP		--	
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	3.0E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.8E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	7.5E-01
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.8E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	6.1E-03
OCDD	3268-87-9	HAP		--	
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.7E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	5.0E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.4E-02
o-Xylene	95-47-6	HAP		--	
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	2.0E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.2E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.1E-02
Chromium III	7440-47-3	HAP	1.4E-03	AP-42, Table 1.4-4 [1]	1.4E-02
Chromium VI	18540-29-9	HAP	0.0E+00	AP-42, Table 1.4-4 [1]	0.0E+00
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	8.4E-04
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	8.5E-03
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	5.0E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.8E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	2.1E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.4E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.3E-02
				NG HAPs Total	**18.90**

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9

https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response

https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Natural gas venting re: shutdown

Natural gas vented per shutdown:	20,000	scf/shutdown
NG % methane (CH_4) composition:	95%	
CH_4 vented per shutdown:	19,000	scf/shutdown
Number of shutdowns per year:	50	shutdowns/yr
CH_4 vented per year:	950,000	scf/yr
Conversion	2,000	lb/ton
CH_4 density at STP:	0.04475	lb/scf
CH_4 Global Warming Potential [1]	28	
Mass of CH_4 vented per year:	42,513	lb/yr
Mass of CH_4 vented per year:	21	tons/yr
CO_{2e} vented per year:	595	tons/yr

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Auxiliary Boiler

Max. Fuel Combustion Rate =	149.13	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	175.13	MMscf/yr	CO_2	1
Hours of Operation =	1,300	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.02E+00	0.67
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	2.24E+00	1.45
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	5.52E+00	3.59
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	7.41E-01	0.48
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	1.07E-01	0.07
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.64E-03	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.74E+04	11,339
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-01	0.21
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-02	0.02
CO_{2e}	-			1.75E+04	11,351
HAPs	See table below				0.17

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2024

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (149.13 MMBtu/hr) = 1.0238 lbs/hr
PM Emissions (tons/yr) = (1.0238 lbs/hr) x (1300 hrs/yr) / (2000 lbs/ton) = 0.665 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Aux Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.1E-06
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.4E-06
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.1E-07
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	1.8E-04
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.1E-04
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	2.6E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.5E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	6.6E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.6E-01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	5.3E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.5E-06
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	4.4E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.0E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	1.8E-05
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.1E-06
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	9.6E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	1.0E-04
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	2.2E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	7.4E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	7.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	4.4E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.3E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.3E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	1.8E-04
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.1E-06
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.0E-04
				NG HAPs Total	**0.17**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Water Bath Heater 1

Max. Fuel Combustion Rate =	10.00	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	79.13	MMscf/yr	CO_2	1
Hours of Operation =	8,760	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.
[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 1 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Water Bath Heater 2

Max. Fuel Combustion Rate =	10.00	MMBtu/hr
Fuel Usage =	79.13	MMscf/yr
Hours of Operation =	8,760	hr/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1.

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 2 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Cooling Tower 1 - Serving Unit 2

Water flow:	120,000	gpm
Hours of Operation:	8760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \qquad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)
TDS = Concentration of total dissolved solids in circulating water (PPM by weight)
η_{Drift} = Drift loss of circulating water (%)
ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal	
PM =	0.76	tons/yr	1.51
PM_{10} =	0.76	tons/yr	1.51
$PM_{2.5}$ [3]=	0.45	tons/yr	

[1] Current BACT requirement for DOE and SWCAA.
[2] South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, December 2022
[3] PM2.5 fraction = 0.6*PM10 fraction, Maricopa County Air Quality, Reporting Emissions From Cooling Towers, January 2025

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Cooling Towers

*Transalta Unit #2 cooling tower testing (12/3/24-01/02/25) - only listed constituent is silica

Total TDS**	576 ppm		
Silica CAS No. 7631-86-9 (TAPs only)	144 ppm	Ratio of silica to TDS	25%
Silica emissions			0.19 tons/yr

**Assume that PM emissions are representative of TDS, therefore 25% of PM emissions are silica

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Cooling Tower 2- Serving Unit 2

Water flow:	120,000	gpm
Total Possible Hours (hrs/yr):	8,760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \quad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)
TDS = Concentration of total dissolved solids in circulating water (PPM by weight)
η_{Drift} = Drift loss of circulating water (%)
ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal
PM =	0.76	tons/yr
PM10 =	0.76	tons/yr
PM2.5=	0.45	tons/yr

[1] Current BACT requirement for DOE and SWCAA.
[2] South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, December 2022
[3] PM2.5 fraction = 0.6*PM10 fraction, Maricopa County Air Quality, Reporting Emissions From Cooling Towers, January 2025

*Transalta Unit #2 cooling tower testing (12/3/24-01/02/25) - only listed constituent is silica

Total TDS**	576 ppm		
Silica CAS No. 7631-86-9 (TAPs only)	144 ppm	Ratio of silica to TDS	25%
Silica emissions			0.19 tons/yr

**Assume that PM emissions are representative of TDS, therefore 25% of PM emissions are silica

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX C: SUPPORTING DOCUMENTATION FOR REGULATORY ANALYSIS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TETRA TECH

Technical Memo

To:	Scott Jeffers and Vincent Light, TransAlta
From:	Debbie Skibicki, PE
Date:	April 22, 2025
Subject:	PSD Analysis for TransAlta Centralia Generating Station Coal-to-Gas Conversion, Reactivation Policy

In discussions with the Washington Department of Ecology (DOE) on April 9, 2025, on the TransAlta Coal-to-Gas (CTG) conversion at the Centralia Generating Station, DOE brought up their interpretation of reactivation policy with respect to that project. DOE specifically mentioned the November 1, 2017 "Guidance on Washington's Prevention of Significant Deterioration [PSD] Permitting Program" (DOE Guidance, Publication no. 17-02-014), Section 2.2.2.1.3 – Restarting Emissions Units. DOE's Guidance document states that "when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways." Section 2.2.2.1.3 of that guidance focuses on reactivation, described as a "permanently" shutdown plant being restarted as a new source. This discussion elaborates on both DOE and EPA guidance and associated site-specific criteria for the TransAlta Centralia site and the CTG project.

1.0 DOE REACTIVATION POLICY

Section 2.2.2.1.3 of the DOE Guidance, under "Reactivation Policy," states the following:

> "*EPA's policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.*[1] *Reactivating a "permanently" shut down source makes the source a new source under current PSD guidance. A source shutting down for more than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

DOE further states:

> *Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

[1] DOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[2] with that intention being the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in their discussions with Lewis County; the regional air permitting authority, Southwest Clean Air Agency (SWCAA), and DOE in addition to vendors, customers, interested stakeholders, etc. has specifically defined their intent to continue operation of the Centralia Plant as a CTG generation resource. These plans were developed prior to the impending ceasing of coal combustion and will continue to build in depth and intensity through the startup of the CTG operations.

DOE refers to the following factors to determine the intent of the owner or operator (the factors will be discussed individually).

1. **The amount of time the facility was out of operation.**

The drivers behind Unit 2 being out of operation are the regulatory process and the construction required for the CTG conversion and life extension of Unit 2. With a smooth regulatory process (started prior to the shutdown, as evidenced in our meetings with DOE), the construction processes could be accomplished with a shutdown of approximately 2 years.

2. **The reason for the shutdown.**

In the 2017 First Amendment to the 2011 Memorandum of Agreement (MOA) between TransAlta and State of Washington, TransAlta agreed to "permanently cease coal-fired power generation" of Unit 2 at the end of 2025. That 2017 Amendment also clarified the anticipated future use of the plant on fuel other than coal. DOE acknowledged TransAlta's consideration of a CTG conversion of Unit 2 in its 2020 Second Revision to its Best Available Retrofit Technology (BART) Order No. 6426 and related Technical Support document for Second BART Order Revision.

3. **Statements by the owner and operator regarding intent.**

As described above, in 2017, TransAlta was actively exploring the possibility of converting the boilers (one or both units) to operate on natural gas instead of coal. To clarify the MOA parties' mutual intent that the plant might continue to generate electricity as long as coal was not the fuel, the parties modified MOA Recital D(5) to clarify that TransAlta would: "permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA." Similarly, Section 6 of the 2017 Amendment revised MOA Section 7, Sentence 2 to read: "Further the State agrees to recognize the Company's cessation of coal fired generation at the

[2] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Facility's boilers prior to the end of their useful lives by taking the early cessation into consideration during future environmental regulatory processes that may adversely affect the Facility's operations."

As recently as this week, TransAlta has been open with Lewis County, SWCAA, DOE and others regarding its intent for fuel conversion at Unit 2 for continued power generation purposes.

4. **The cost and time required to reactivate the facility.**

EPA's reactivation guidance largely applies to facilities shutting down/being mothballed and subsequently being restarted. The DOE referenced guidance (and that mentioned here) does not include conversion to another fuel type, as is discussed in this instance. The costs to reactivate after being mothballed (deactivated for extended period) are approximately $1.5 million including efforts to dehumidify/dry out the boiler and turbine, maintain the units with respect to moisture and corrosion, and then prepare the unit to run again.

For this project, TransAlta is proposing fuel conversion of Unit 2 in addition to life extension, for which the total cost would approximately 1/3 or less of the cost of new build natural gas fired combined cycle turbine unit (including contingency and engineering, procurement, and construction premium). The life extension costs would be incurred to allow the facility to run for another 17 years and are not directly related to the fuel conversion. Those costs would include replacing the cooling towers, feedwater heaters, etc. As discussed above, the total effort could be accomplished in approximately 2 years.

5. **Status of the facility's permits.**

TransAlta will be applying for the appropriate construction permits for their proposed action, as current agency discussions indicate. Other permits (including the Title V Operating Permit #SW98-8-R5 and Acid Rain permit) will remain in force. TransAlta will apply for a Title V modification to update the permit to reflect current operations per the Title V modification requirements in WAC 173-401-725 and would provide an updated compliance plan under the Acid Rain rules. In addition, TransAlta will continue to maintain emissions inventory reporting as required by SWCAA rules 400-105(1).

6. **The record of ongoing maintenance and inspections that were conducted during the shutdown.**

TransAlta will be performing ongoing maintenance and inspections while construction on Unit 2 is taking place for the fuel conversion. The maintenance and inspections would occur on the facility as a whole, in maintaining existing, unchanged units; in the construction of new units; and in the removal of no longer needed components. TransAlta can provide those records during the conversion/construction/shutdown period upon request.

7. **Whether the shutdown was considered as a decrease in a "netting" calculation.**

The temporary shutdown of Unit 2 has not been considered as a decrease in a "netting calculation." The previous 2-year average emissions baseline is being used to determine if a major modification has been triggered for Unit 2 in the CTG conversion. However, no netting occurred or is proposed in the regulatory applicability process.

8. **Whether the allowable emissions level after restarting the facility are higher than as of the date of the shutdown.**

The allowable emissions level of Unit 2 following the CTG conversion will be less than the previous coal 2-year average baseline for all PSD pollutants with the possible exception of volatile organic compounds (VOC). Coal combustion creates negligible VOC emissions, so the previous baseline level was essentially zero.

In addition to the criteria above and TransAlta's clear intent to continue operation of the Centralia Plant as a CTG generation resource, DOE also was aware of the plans and indicated as such in its July 2020 Second Revision to its Best Available Retrofit Technology (BART) Order (Order No. 6426) and related Technical Support Document. The Technical Support document states on Page 1, "Ecology is also modifying the compliance schedule to eliminate

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

the requirement to demolish the coal units to align the BART order's language with language in the MOA between the State of Washington and TransAlta."

DOE's Technical Support Document also quotes the 2017 MOA and notes that SWCAA would have authority over air permitting for conversion: "If TransAlta decides to ***switch to non-coal power generation***, a Notice of Construction application would need to be submitted ***to Southwest Clean Air Agency*** by the company." This language implies that the question of reactivation was not at issue in those discussions.

2.0 CONCLUSION

As mentioned in the DOE PSD Guidance document as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear – the Unit 2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of that goal. That driver and the other criteria support the conclusion that the limited shutdown of Unit 2 was "not intended to be permanent." Thus, Unit 2 should not be viewed as a new source under these circumstances.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX D: SUPPORTING DOCUMENTATION FOR BACT ANALYSES

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

RBLC CLEARINGHOUSE LISTINGS

LARGE NATURAL GAS FIRED BOILERS (Process code 11.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT - VOCs
LA-0406	MCA GEIMAR SITE	LA	7/24/2024	CO MeOH Auxiliary Boiler (EQT0001)	321 MMBtu/hr	Good combustion practices	0.0027 lb/MMBtu
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	TX	2/5/2024	Auxiliary Boiler	>250 MMBtu/hr	Good combustion practices	0.016 lb/MMBtu
LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR • Auxiliary Boiler	1100 MMBtu/hr	Good combustion practices	0.0016 lb/MMBtu
LA-0394	SHELL CHEMICAL GEISMAR PLANT	LA	12/12/2023	01-22 • A0-5 Boiler	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
TX-0936	VALERO BILL GREEHEY REFINERY	TX	3/29/2022	BOILER	334 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Good combustion practices and compliance with 40 CFR 63, Subpart DDDDD	0.0055 lb/MMBtu
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 MMBtu/hr	Natural gas only, good combustion practices, following manufacturing specs for SU/SD	0.0054 lb/MMBtu
	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 MMBtu/hr	Natural gas only, good combustion practices, following manufacturing specs for SU/SD	0.0054 lb/MMBtu
MI-0440	MICHIGAN STATE UNIVERSITY*	MI	5/22/2019	EUSTMBoiler	300 MMBtu/hr	Good combustion practices	0.0053 lb/MMBtu
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Auxiliary Boller	773 MMBtu/hr	Good combustion practices	
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 • Boiler 1 (EQT0003)	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 • Boiler 2 (EQT0004)	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu

Original construction dates 1970, modified in 2019

* Uses No 2 fuel oil as backup

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

EXISTING COAL TO GAS CONVERSIONS

FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT (or FACTOR) - VOCs
Nevada Power Company dba Nevada Energy	NV	7/2/2024 (app submittal date, not final)	North Valmy Generating Station - Unit 1	2708 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
			North Valmy Generating Station - Unit 2	3048 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
PacifiCorp Energy	WY	4/3/25 (app submittal date, not yet issued)	Naughton Unit 1	1850 MMBtu/hr	None listed	0.004 lb/MMBtu
			Naughton Unit 2	2400 MMBtu/hr	None listed	0.004 lb/MMBtu
PacifiCorp Energy	WY	12/28/2022	Bridger Unit 1	3000 MMBtu/hr	None listed	0.0054 lb/MMBtu
			Bridger Unit 2	3000 MMBtu/hr	None listed	0.0054 lb/MMBtu
Midwest Generation, LLC	IL	10/16/2015	Unit 6	3543 MMBtu/hr	None listed	0.0027 lb/MMBtu
			Unit 7 (two boilers, combined capacity)	6034 MMBtu/hr	None listed	0.0027 lb/MMBtu
			Unit 8 (two boilers, combined capacity)	6384 MMBtu/hr	None listed	0.0027 lb/MMBtu

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Data Inputs

Select the type of oxidizer: Catalytic Oxidizer - Fixed Bed

Enter the following information for your emission source:

Composition of Inlet Gas Stream

Pollutant Name	Concentration (ppmv)	Lower Explosive Limit (LEL) (ppmv)*	Heat of Combustion (Btu/scf)	Molecular Weight
Hexane	1	11,000	4,667	86
Formaldehyde	0	70,000	1,020	30
Butane	1	19,000	3,101	58

Note: The lower explosion limit (LEL), heat of combustion and molecular weight for some commonly used VOC/HAP are provided in the table below. In addition, the heat of combustion to be entered in column D is a lower heating value (LHV), not a higher heating value (HHV).

Enter the design data for the proposed oxidizer:

Number of operating hours/year	5,168	hours/year	
Inlet volumetric flow rate(Q_{wi}) at 77°F and 1 atm.	1,770,219	scfm	
Pressure drop (ΔP)	23	inches of water*	* 23 inches of water is a default pressure drop for catalytic oxidizers. User should enter actual value, if known.
Motor/Fan Efficiency (ε)	60	percent*	* 60% is a default fan efficiency. User should enter actual value, if known.
Inlet Waste Gas Temperature (T_{wi})	330	°F	
Operating Temperature (T_{fi})	900	°F	* Note: Default value for Tfi is 900°F for catalytic oxidizers. Use actual value if known. Tfi for catalytic oxidizers is typically between 300 and 900°F.
Destruction and Removal Efficiency (DRE)	99	percent*	* 99 percent is a default control efficiency. User should enter actual value, if known.
Estimated Equipment Life	17	Years	

Percent Energy Recovery (HR) = 70 percent

0
35
50
70

Catalyst Data:

Estimated catalyst life (y)	4	years	* 4 years is a default value. User should enter actual value, if known.
Catalyst Unit Cost (CC)	888	$/ft³	
Space velocity for catalyst (Φ)	30,000	/hour	* 30,000 per hour is a default value. User should enter actual value, if known.

Enter the cost data:

Desired dollar-year	2023				
CEPCI* for 2023	797.9	Enter the CEPCI value for 2023	390.6	1999 CEPCI	*Enter dollar year first.
Annual Interest Rate (i)	7.50	%			
Electricity ($Cost_{elect}$)	0.068	$/kWh			
Natural Gas Fuel Cost ($Cost_{fuel}$)	0.01428	$/scf			
Operator Labor Rate	$70.00	per hour			
Maintenance Labor rate	$70.00	per hour			
Contingency Factor (CF)	10.0	Percent			* 10 percent of the total capital investment F45is a default value for construction contingencies. User may enter values between 5 and 15 percent.

* CEPCI is the Chemical Engineering Plant Cost Escalation/De-escalation Index. The use of CEPCI in this spreadsheet is not an endorsement of the index for purposes of cost escalation or de-escalation, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Parameters for Common Compounds:

Compound	LEL (ppmv)	Heat of Combustion (Btu/scf)	Molecular Weight
Methane*	50,000	911	16.04
Ethane	30,000	1,631	30.07
Propane	21,000	2,353	44.09
Butane	19,000	3,101	58.12
Pentane	14,000	3,709	72.15

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hexane	11,000	4,404	86.17
Octane	10,000	5,796	114.23
Nonane	8,000	6,493	128.25
Decane	8,000	7,190	142.28
Ethylene**	27,000	1,499	28.05
Propylene	20,000	2,182	42.08
Cyclohexane	13,000	4,180	84.16
Benzene**	14,000	3,475	78.11
Toluene**	11,000	4,274	92.14
Methyl Chloride (Chloromethane)**	82,500	705	50.49
Footnotes * Greenhouse gas. ** Hazardous air pollutant.			

Data Element	Default Value	Sources for Default Values used in the calculation . . .	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Catalyst Cost ($/ft^3)	650	Based on 2014 vendor data for base metal oxide catalyst.	$888, used consumer price index inflation calculator (https://www.bls.gov/data/inflation_calculator.htm) to update December 2014 data to April 2025	Check with catalyst vendor.
Electricity Cost ($/kWh)	0.0641	Average annual electricity cost for industrial plants is based on 2016 price data compiled by the U.S. Energy Information Administration from data reported on Form EIA-861 and 861S, (https://www.eia.gov/electricity/annual/html/epa_02_04.html).	$0.068/kWh, https://www.eia.gov/state/print.php?sid=WA, industrial rate in Washington as of February 2025	Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/Mscf)	3.51	Annual average price paid for natural gas by industrial facilities in 2016 from the U.S. Energy Information Administration. Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.	14.28 $/Mscf - March 2025 rate for industrial facilities in Washington https://www.eia.gov/dnav/ng/hist/n3035wa3m.htm	Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.
Operator Labor ($/hour)	26.61	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for operators based on data for plant and System Operators – other (51-8099).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.
Maintenance Labor ($/hour)	27.40	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for maintenance workers based on electrical and electronics commercial and industrial equipment repairers (49-2094).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Design Parameters

The following design parameters for the oxidizer were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Composition of Inlet Gas Stream		
Pollutant Name	**Concentration in Waste Stream (ppmv) From Data Inputs Tab**	**Adjusted Concentration with Dilution Air (ppmv)**
Hexane	1	NA
Formaldehyde	0	NA
Butane	1	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
Total	1	0

Constants used in calculations:

Temperature of auxiliary fuel (T_{af}) =	Reference Temperature (T_{ref}) =	77.0 °F
Density of auxiliary Fuel at 77 °F (ρ_{af}) =		0.0408 lb/ft^3
Heat Input of auxiliary fuel ($-\Delta h_{caf}$) =		21,502 Btu/lb
Density of waste gas at 77 °F (ρ_{wi}) =		0.0739 lb/ft^3
Mean Heat Capacity of Air (C_{pmair}) =	(For catalytic oxidizers)	0.248 Btu/lb °F

Parameter	Equation	Calculated Value	Units	Value	Units
Sum of volume fraction of combustible components =	= ($\sum x_i$) =	1	ppmv		
Lower Explosive Limit of waste gas (LEL_{mix})	= $[\sum((x_j)/((\sum x_i) \times LEL_j))]^{-1}$ =	15,319	ppmv		
	Where x_j is the volume fraction and LEL_j the lower explosive limit for each combustible component in the waste gas.				
% LEL_{mix}	= (Total Combustible Conc. In Mixture/LEL_{mix}) × 100 =	0.01	percent	* Note: Since the LEL of the waste gas stream is below 25%, no dilution air is needed.	
Dilution Factor	= (LEL_{mix} x 0.249)/($\sum x_i$) =	Not applicable			
Lower Explosive Limit (LEL) of waste gas after addition of dilution air	= (Total Adjusted Conc. With Dilution Air/LEL_{mix}) × 100 =	Not Applicable			
Inlet volumetric flow rate(Qwi) at 77°F and 1 atm.	(From Data Entry Tab) =	1,770,219	scfm		
Oxygen Content of gas stream	= 100 - ($\sum x_j \times 100/10^6$) =	20.90	percent		
Fan Power Consumption (FP)	= $[(1.17 \times 10^{-4}) \times Q_{wi} \times \Delta P]/\varepsilon$	7939.4	kW		
Q_{wo}	≈ Q_{wi} =	1,770,219	scfm		
Operating temperature of oxidizer (T_{fi})	(From Data Entry Tab)	900	°F		
Temperature of waste gas at outlet to preheater (T_{wo})	= Heat Recovery × (T_{fi} - T_{wi}) + T_{wi} =	729	°F	Note: this temperature is relevant for incinerators, but not for th	
Temperature of flue gas exiting the oxidizer (T_{fo})	= T_{fi} - T_{wo} + T_{wi} =	501	°F		
Heat Input of waste gas ($-\Delta h_{cwi}$)					
	= $\sum(-\Delta h_{ci})\, x_i$ Where ($-\Delta h_{ci}$) is the heat of combustion and x_i the fraction of component "i" at 77 °F.	0.00	Btu/scf	0.1	Btu/lb

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Estimated Auxiliary Fuel Flow (Q_{af}) at 77 °F and 1 atm.	(Calculated using Equation 2.21 in Chapter 2 of the Cost Manual)	9,457.42 scfm
Auxiliary fuel Energy Input =		8,296,824 Btu/min
Minimum Energy required for combustion stabilization =	= 5% × Total Energy Input = $0.05 \times \rho_{fi} \times Q_{fi} \times C_{pmfi} \times (T_{fi} - T_{ref})$ =	1,380,052 Btu/min
Is the calculated auxiliary fuel sufficient to stabilize combustion? (Note: If the auxiliary fuel energy input > 5% of Total Energy Input, then the auxilary fuel is sufficient.)		Yes
Auxiliary fuel flow (Qaf) at 77°F and 1 atm. =		9,457 scfm
Total Volumetric Throughput (Q_{tot}) at 77 °F and 1 atm.	$= Q_{fi} = Q_{wo} + Q_a + Q_{af} = Q_{wi} + Q_{af}$ =	1,779,676 scfm

Calculation of Catalyst Volume and Estimated Temperature of Waste Gas Entering the Catalyst Bed

Volumetric Flow Rate at 60 °F and 1 atm (Q_{ft})	$= Q_{tot} \times (519)/(77\ °F + 460)$ =	1,720,022 scfm
Catalyst Volume (Vol_{cat})	Where Q_{ft} is the volumetric flow rate of the waste gas (Q_{fi}) corrected to 60 °F and 1	3440.04 ft^3
Estimated inlet temperature to the catalyst bed (T_{ri}) =	(Calculated using Equation 2.28 in Chapter 2 of the Cost Manual)	900 °F

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1060

Future Worth Factor

Parameter	Equation	Calculated Value
Future Worth Factor (FWF) =	$i\,[1/(1+i)^y - 1]$ = Where y = Catalyst Life and i= Interest Rate	0.2236

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Cost Estimate

Direct Costs			
Total Purchased equipment costs (in 2023 dollars)			
Incinerator + auxiliary equipment[a] (A) =			
Equipment Costs (EC) for a Fixed Bed Catalytic Oxidizer	= (1,443 x Qtot^(0.5527)) x (2023 CEPI/1999 CEPCI) =	$8,395,490	in 2023 dollars
Instrumentation[b] =	0.10 × A =	$839,549	
Sales taxes =	0.03 × A =	$251,865	
Freight =	0.05 × A =	$419,775	
	Total Purchased equipment costs (B) =	$9,906,678	in 2023 dollars

Footnotes
a - Auxiliary equipment includes equipment (e.g., duct work) normally not included with unit furnished by incinerator vendor.
b - Includes the instrumentation and controls furnished by the incinerator vendor.

Direct Installation Costs (in 2023 dollars)			
Foundations and Supports =	0.08 × B =	$792,534	
Handling and Erection =	0.14 × B =	$1,386,935	
Electrical =	0.04 × B =	$396,267	
Piping =	0.02 × B =	$198,134	
Insulation for Ductwork =	0.01 × B =	$99,067	
Painting =	0.01 × B =	$99,067	
Site Preparation (SP) =		$0	
Buildings (Bldg) =		$0	
	Total Direct Installaton Costs =	$2,972,003	
Total Direct Costs (DC) =	B + C + SP + Bldg =	$12,878,682	in 2023 dollars

Total Indirect Installation Costs (in 2023 dollars)			
Engineering =	0.10 × B =	$990,668	
Construction and field expenses =	0.05 × B =	$495,334	
Contractor fees =	0.10 × B =	$990,668	
Start-up =	0.02 × B =	$198,134	
Performance test =	0.01 × B =	$99,067	
	Total Indirect Costs (IC) =	$2,773,870	
Continency Cost (C) =	CF(IC+DC)=	$1,565,255	
Total Capital Investment =	**DC + IC +C =**	**$17,217,807**	**in 2023 dollars**

Direct Annual Costs

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Catalyst Replacement Cost	= 1.08 × CC × Vol_{cat} × FWF Where CC is the $/ft^3 cost for the replacement catalyst; Vol_{cat} is the volume of catalyst required based on the waste gas flow rate (Q_{ft}) and the catalyst space velocity (Φ); and FWF is the future worth factor.	$737,581
Annual Electricity Cost	= Annual Electricity Usage × Operating Hours/year × Electricity Price =	$2,790,107
Annual Fuel Costs for Natural Gas	= $Cost_{fuel}$ × Fuel Usage Rate × 60 min/hr × Operating hours/year	$41,876,927
Operating Labor	Operator = 0.5hours/shift × Labor Rate × (Operating hours/8 hours/shift)	$22,610
	Supervisor = 15% of Operator	$3,392
Maintenance Costs	Labor = 0.5 hours/shift × Labor Rate × (Operating Hours/8 hours/shift)	$22,610
	Materials = 100% of maintenance labor	$22,610
Direct Annual Costs (DC) =		**$45,475,836 in 2023 dollars**

Indirect Annual Costs

Overhead	= 60% of sum of operating, supervisor, maintenance labor and maintenance materials	$42,733
Administrative Charges	= 2% of TCI	$344,356
Property Taxes	= 1% of TCI	$172,178
Insurance	= 1% of TCI	$172,178
Capital Recovery	= CRF[TCI-1.08(cat. Cost)]	$1,740,650
Indirect Annual Costs (IC) =		**$2,472,095 in 2023 dollars**
Total Annual Cost =	**DC + IC =**	**$47,947,931 in 2023 dollars**

Cost Effectiveness

Cost Effectiveness = (Total Annual Cost)/(Annual Quantity of VOC/HAP Pollutants Destroyed)

Total Annual Cost (TAC) =	$47,947,931 per year in 2023 dollars
VOC/HAP Pollutants Destroyed =	57.2 tons/year
Cost Effectiveness =	$838,100 per ton of pollutants removed in 2023 dollars

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

RBLC CLEARINGHOUSE LISTINGS

INDUSTRIAL-SIZE NATURAL GAS FIRED BOILERS (Between 100 and 250 MMBtu/hr, Process code 12.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT - VOCs
IN-0382	DUKE ENERGY INDIANA - CAYUGA GENERATING STATION	IN	2/14/2025	Auxiliary Boiler	225 MMBtu/hr	Good combustion practices	0.005 lb/MMBtu
IN-0371	WABASH VALLEY RESOURCES	IN	1/11/2024	Auxiliary Boiler - Unit 1C	217.65 MMBtu/hr	None	
IL-0134	CRONUS CHEMICALS, LLC	IL	12/21/2023	Boiler	179.4 MMBtu/hr	Oxidation catalyst, good combustion practices	0.0014 lb/MMBtu
OH-0391	VALENCIA PROJECT LLC	OH	10/27/2023	Boiler #1 and 2	122 MMBtu/hr	Good combustion practices	0.005 lb/MMBtu
LA-0397	INDORAMA VENTURES OLEFINS, LLC - WESTLAKE ETHYLENE	LA	4/29/2022	EQT0011	248 MMBtu/hr	None	
AK-0086	KENAI NITROGEN OPERATIONS	AK	3/26/2021	PKG Boiler	243 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
LA-0397	SHINTECH LOUISIANA LLC - PLAQUEMINE PLANT 3	LA	1/19/2021	Boiler D	250 MMBtu/hr	Good combustion practices	0.0026 lb/MMBtu
MI-0445	INDECK NILES, LLC	MI	11/26/2019	AuxBoiler	182 MMBtu/hr	Good combustion practices	0.004 lb/MMBtu

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX E: AIR DISPERSION MODELING ANALYSIS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Air Quality Dispersion Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

Lewis County, Washington

December 2025

Prepared for

TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, Washington 98531

Submitted to

Southwest Clean Air Agency
5101 NE 82nd Ave.
Vancouver, Washington 98662
and
Washington Dept. of Ecology
300 Desmond Drive SE
Lacey, Washington 98503

Prepared by

TETRA TECH
10 Post Office Square, 11th Floor
Boston, MA 02109

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table of Contents

1.0 INTRODUCTION 1

2.0 FACILITY DESCRIPTION AND REGULATORY APPLICABILITY 4

2.1 Site Location 4
2.2 Project Description 4
2.3 Summary of Annual Potential Emissions 4
2.4 Ambient Air Quality Regulatory Criteria 5
2.4.1 National Ambient Air Quality Standards 5
2.4.2 New Source Review 7
2.4.3 Prevention of Significant Deterioration 7
2.4.4 Toxic Air Pollution Sources Review 8

3.0 AIR QUALITY IMPACT ASSESSMENT METHODOLOGY 10

3.1 Introduction 10
3.2 Source Data and Operating Scenarios 12
3.3 Model Selection 16
3.4 Meteorological Data for AERMOD 16
3.5 Land Use 17
3.6 Good Engineering Practice Stack Height Analysis 18
3.7 Receptor Grid and AERMAP Processing 19
3.8 Ambient Background Data 20
3.9 Modeling Methodology 23
3.9.1 NO_2 Modeling Methods 24
3.10 Assessment of Secondary Particulate and Ozone 24
3.11 Toxic Air Pollutant Source Impact analysis 25

4.0 AIR QUALITY MODELING RESULTS 25

4.1 Introduction 25
4.2 Load Analysis 26
4.3 Secondary Pollutant Assessment 26
4.3.1 Secondary $PM_{2.5}$ Assessment 26
4.3.2 Ozone Ambient Impact Assessment 27
4.4 Project Impacts Compared to the SILs 28
4.5 NAAQS Analysis 28
4.6 Toxic Air Pollutant Modeling Results 29

5.0 REFERENCES 31

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

List of Tables

Table 2-1. Project Annual Potential Emissions (tons per year, tpy) 5
Table 2-2. National Ambient Air Quality Standards 5
Table 2-3. Centralia Coal to Gas Baseline Net Emissions and PSD Applicability Thresholds 7
Table 2-4. TransAlta Project De Minimis TAP Emissions 8
Table 2-5. TransAlta Project SQER TAP Emissions 9
Table 2-6. TransAlta Project TAP Emissions for Dispersion Modeling 9
Table 2-7. TransAlta Project 1998 SQER TAP Emissions 10
Table 2-8. TransAlta Project 1998 TAP Emissions for Dispersion Modeling 10
Table 3-1. SILs and NAAQS 11
Table 3-2. Physical Stack Characteristics 13
Table 3-3. Stack Exhaust Parameters and Emission Rates 14
Table 3-4. Proposed Air Quality Background Concentrations 23
Table 3-5. Margin between Ambient Air Quality Concentrations and the NAAQS 23
Table 4-1. SILs Analysis Results 28
Table 4-2. NAAQS Analysis Results 29
Table 4-3 TAPs Analysis Results 30
Table 4-4 1998 TAPs Analysis Results 30

List of Figures

Figure 1-1. Facility Location Map 3
Figure 3-1. Five-year (2020-2024) Wind Rose of Wind Measurements at Olympia Meteorological Station 17
Figure 3-2. Urban / Rural Land Use Determination within a 3 km radius 18
Figure 3-3. Full Nested Cartesian Receptor Grid including the Refined Receptor Grid 21
Figure 3-4. Zoomed to Inner Grids of the Nested Cartesian Receptor Grid 22
Figure B-1. AERMOD Predicted 1-hour NO_2 Concentration Contours 1
Figure B-2. AERMOD Predicted Annual (2020) NO_2 Concentration Contours 2
Figure B-3. AERMOD Predicted 24-Hour $PM_{2.5}$ Concentration Contours 3
Figure B-4. AERMOD Predicted Annual $PM_{2.5}$ Concentration Contours 4

List of Appendices

Appendix A: Unit #2 Load Analysis
Appendix B: Project Predicted Concentration Contours for NAAQS Analyses

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Acronyms/Abbreviations

µg/m^3	micrograms per cubic meter
ARM2	Ambient Ratio Method 2
ASIL	Acceptable Source Impact Levels
BPIP	Building Profile Input Program
CFR	Code of Federal Regulations
CO	carbon monoxide
GEP	Good Engineering Practice
GHGs	greenhouse gases
GRSM	Generic Reaction Set Method
H1H	highest first high
H2H	highest second high
H_2SO_4	sulfuric acid
H4H	highest fourth high
H6H	highest sixth high
H8H	highest eighth high
km	kilometer
lb	pound
m	meters
MMBtu/hr	million British thermal units per hour
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Data
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSR	New Source Review
O_3	ozone
OLM	Ozone Limiting Method
Pb	lead
PM_{10}	particulate matter with a diameter equal to or less than 10 microns

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
ppb	parts per billion
ppm	parts per million
The Project	Conversion of coal to natural gas firing in Unit #2 project
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
Report	Air Quality Modeling Report for the Project (this document)
SER	Significant Emission Rate
SIL	Significant Impact Level
SO_2	sulfur dioxide
SQER	small quantity emission rates
TAP	toxic air pollutant
tBACT	toxics Best Available Control Technology
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WDOE	Washington Department of Ecology

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility, which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be passed through or bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas-starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the annual emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application which requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. The proposed methodology for the air quality dispersion modeling analyses was submitted to the Washington Department of Ecology (WDOE) and the Southwest Clean Air Agency (SWCAA) in a Modeling Protocol. WDOE (in the role of designated model reviewer) reviewed and approved the proposed approach on 10/13/2025. This document is the air quality dispersion modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project's location and expected emissions, along with an applicability assessment relative to key regulations related to the air quality impact analysis. Section 3 presents a detailed description of the modeling approach proposed for evaluating air quality impacts of the proposed Project including: source data and operating scenarios, model selection criteria, an urban/rural land use determination, Good Engineering Practice (GEP) stack height determination and building dimensions for model input, meteorological data, the receptor grids, ambient monitored background concentrations, as well as assessments for secondary ozone (O_3) and particulate matter with diameters of less than 2.5 micrometers ($PM_{2.5}$). The air quality modeling results demonstrating compliance are presented in Section 4. References cited in the document are presented in Section 5. Electronic modeling files are being submitted to the agencies with this Report. To facilitate the review of this Report and modeling files, the individual familiar with the dispersion modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Modeling Consultant: Liz Hendrick, CCM
Tetra Tech, Inc.
10 Post Office Square, 11th Floor
Boston, MA 02109
Telephone: (978) 303-8524
Email: Liz.Hendrick@tetratech.com

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

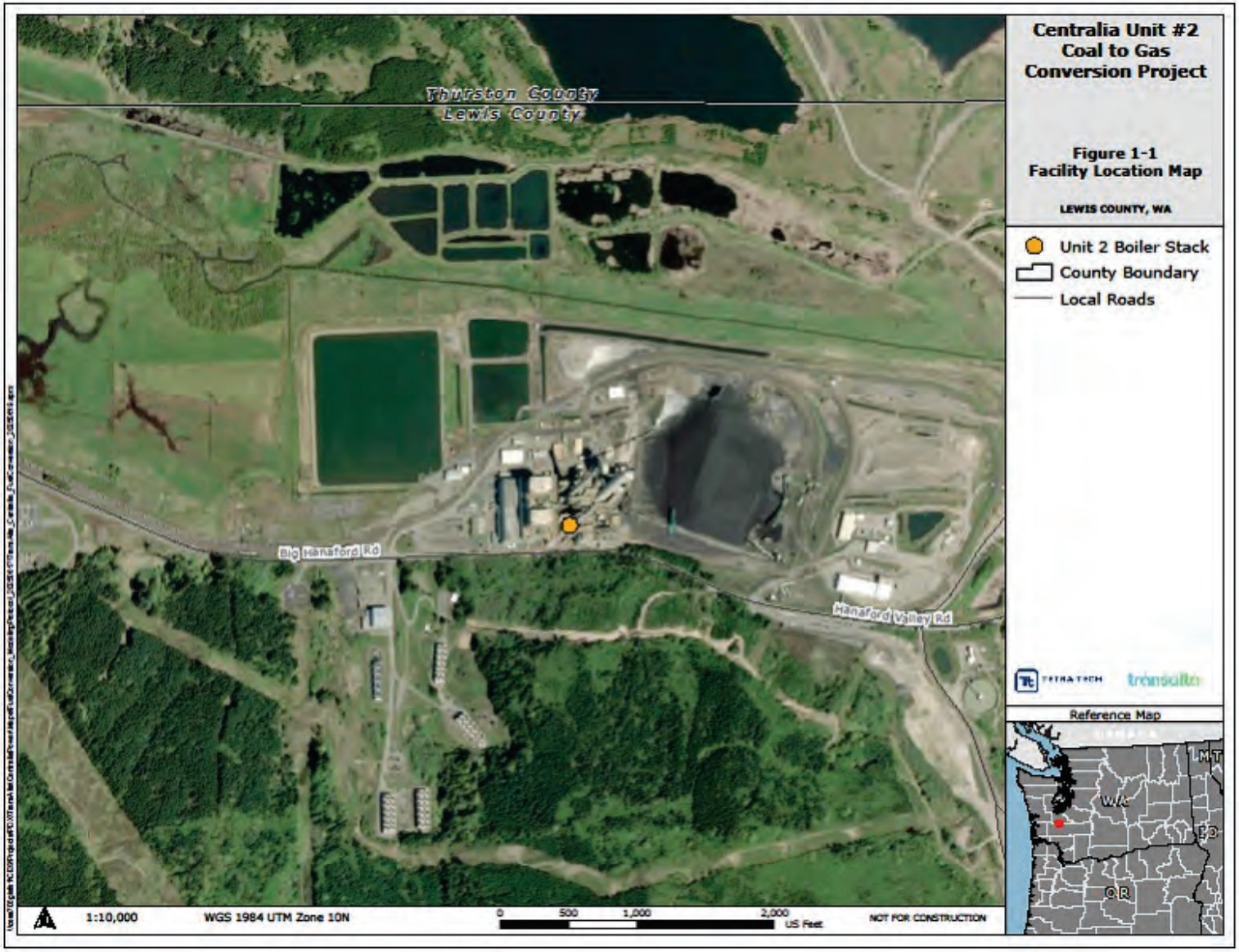


Figure 1-1. Facility Location Map

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

2.0 FACILITY DESCRIPTION AND REGULATORY APPLICABILITY

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The Project is surrounded by two fences to restrict public access to the generation area and the cooling tower area. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land.

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to be used to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The Project will be fully contracted to Puget Sound Energy (the Customer), and the Customer will be responsible for procuring and delivering all fuel to the converted facility and will also control dispatch of the facility. The Project is not designed nor intended to operate continuously or at a high capacity or baseload factor. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. In any event, the facility will not operate for more than 59 percent of all hours on an annual basis over the life of the Project. TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

Given the marginal cost of the unit, it is expected only during periods of high demand and reliability need, with the majority of operating hours expected at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project will include the replacement of the existing auxiliary boiler (currently diesel-fired, will be solely natural gas-fired), two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The natural gas will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boilers via a short 1,300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-1. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied,

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

as necessary. Potential emission rates for Unit #2 are based upon full load operation for 5,168 hours per year (i.e., 59% capacity factor) combusting natural gas. Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year.

Table 2-1. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[c, b]	Water Bath Heaters (2)[d, b]	Cooling Towers (2)	Project Wide Totals[e]
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.
[e] The emissions listed are slightly different than those provided in the application due to rounding.

2.4 Ambient Air Quality Regulatory Criteria

The USEPA has promulgated regulations that establish National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments. The NAAQS are established in 40 Code of Federal Regulations (CFR) 50 and incorporated in the Washington air pollution regulations. The PSD regulations are established in 40 CFR 52 and incorporated in Washington's air pollution control regulations. These regulations and guidelines provide the basis for an evaluation of the potential impacts of the proposed Project on air quality.

2.4.1 National Ambient Air Quality Standards

The USEPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are sulfur dioxide (SO_2), particulate matter with diameters of less than 10 micrometers (PM_{10}), $PM_{2.5}$, nitrogen dioxide (NO_2), carbon monoxide (CO), O_3, and lead (Pb). The NAAQS have been developed for short-term periods of 24 hours or less and annual averages. The NAAQS include both "primary" and "secondary" standards, where the primary standards are set to protect human health, allowing an adequate margin of safety. Secondary standards are set to protect public welfare from any known or anticipated adverse effects associated with the presence of air pollutants in the ambient air. The current NAAQS are provided in Table 2-2.

Table 2-2. National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS (µg/m³) [a]	
		Primary	Secondary
NO_2	Annual[b]	100	Same

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Pollutant	Averaging Period	NAAQS (µg/m³) [a]	
		Primary	Secondary
	1-hour[c]	188	None
SO_2	Annual[b,d]	80	26.2
	1-hour[e]	196	None
CO	8-hour[f]	10,000	None
	1-hour[f]	40,000	None
PM_{10}	24-hour[g]	150	Same
$PM_{2.5}$	Annual[h]	9	15
	24-hour[i]	35	Same
O_3	8-hour[j]	0.070 ppm[k]	Same
Pb	3-month[b]	0.15	Same

[a] µg/m³ = micrograms per cubic meter
[b] Not to be exceeded.
[c] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average must not exceed 100 parts per billion (ppb) (188 µg/m³).
[d] The annual average secondary standard for SO_2 is based on the annual mean averaged over 3 years and must not exceed 10 ppb.
[e] To attain this standard, the 3-year average of 99th percentile of the daily maximum 1-hour average must not exceed 75 ppb (196 µg/m³).
[f] Not to be exceeded more than once per year.
[g] Not to be exceeded more than once per year on average over 3 years.
[h] To attain this standard, the 3-year average of weighted annual mean $PM_{2.5}$ concentrations must not exceed 9 µg/m³.
[i] To attain this standard, the 3-year average of 98th percentile of 24-hour concentrations must not exceed 35 µg/m³.
[j] To attain this standard, the 3-year average of the fourth highest daily maximum 8-hour average O_3 concentrations averaged over 3 years must not exceed 0.070 ppm.
[k] ppm = parts per million

One of the primary goals of federal and state air pollution regulations is to ensure that ambient air quality is in compliance with the NAAQS. Toward this end, every area of the United States has been designated as “attainment”, “unclassifiable” or “nonattainment” for each criteria pollutant. In areas designated as attainment, the air quality with respect to the pollutant is equal to or better than the NAAQS. These areas are under a mandate to maintain, i.e., prevent significant deterioration of such air quality. In areas designated as unclassifiable, there is limited air quality data, and these areas are treated as attainment areas for regulatory purposes. In areas designated as nonattainment for a particular pollutant, the air quality with respect to that pollutant is worse than the NAAQS. These areas must take actions to improve air quality and attain compliance with the NAAQS within a certain period of time.

If a new major source of air pollution is proposed, it must undergo New Source Review (NSR) air permitting. The NSR air permitting regulations contain two distinct programs, one for sources proposed in attainment/unclassifiable areas and one for sources in nonattainment areas. The NSR program for sources proposed in attainment/unclassifiable areas is known as the PSD program. The NSR program for sources proposed in non-attainment areas is known as nonattainment new source review (NNSR).

The Facility location in Lewis County, Washington state is presently classified as attainment/unclassifiable for all criteria pollutants. Thus, emissions of criteria pollutants from the Project are evaluated with respect to the PSD program. The requirements of the NSR program are discussed in more detail in the following subsections.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

2.4.2 New Source Review

NSR applies to new major sources of air pollutants and major modifications of existing major sources. The NSR program includes two distinct permitting programs, PSD permitting for projects located in areas designated as unclassified or attainment with the NAAQS, and NNSR permitting for projects located in areas designated as nonattainment with the NAAQS. As an area may be in attainment with one or more NAAQS, but in nonattainment with one or more other NAAQS at the same time, an individual project may be subject to both PSD and NNSR permitting, depending upon its potential emissions on a pollutant-by-pollutant basis. The federal PSD program under 40 CFR 52.21 applies to subject sources in the U.S. and the program is administered by the USEPA.

2.4.3 Prevention of Significant Deterioration

The Project is located at the TransAlta Centralia Generating facility which is currently an existing major source for emissions of nitrogen oxides (NO_X), CO, SO_2, particulate matter (PM), PM_{10}, $PM_{2.5}$, volatile organic compounds (VOCs), sulfuric acid (H_2SO_4), and greenhouse gases (GHGs). Accordingly, the Project is considered a modification of the existing Centralia facility and is subject to PSD permitting if it meets the definition of a major modification under this permitting program. This analysis focused on Unit #2, evaluating the proposed overall project emissions with respect to the Unit #2 baseline emissions, and using 2022-2023 as the baseline period. The modification results in a net decrease in emissions from Unit #2 at the existing generating facility (except for VOC). Table 2-3 provides a comparison of the Project's potential emissions to the PSD Significant Emission Rates (SER). VOC is the only pollutant that exceeds the SER. As such, the Project will not result in a significant emissions increase (i.e. greater than the respective SER) for all criteria pollutants and does not trigger a PSD modeling analysis. An air dispersion modeling analysis was conducted in accordance with USEPA guidance as described in the Modeling Protocol. Modeling was conducted for Facility emissions of CO, NO_X, PM_{10}, $PM_{2.5}$ and SO_2 because NAAQS for these pollutants have been established. VOC is not modeled, as there is no NAAQS for that pollutant. However, because VOC is a precursor to the formation of photochemical oxidants, O_3 impacts are assessed (as described in Section 3.10).

Table 2-3. Centralia Coal to Gas Baseline Net Emissions and PSD Applicability Thresholds

Pollutant	Unit #2[a] tpy	Auxiliary Boiler[b] tpy	Water Bath Heaters (2)[c] tpy	Cooling Towers (2) tpy	Project Wide Totals tpy	PSD Significant Emission Rate tpy
NO_X	-	1.5	1.3	-	2.8	40
CO	-	3.6	3.2	-	6.8	100
VOC	57.9	0.5	0.4	-	58.8	40
PM_{10}	-	0.7	0.6	3.0	4.3	15
$PM_{2.5}$	-	0.7	0.6	1.8	3.1	10
SO_2	-	0.07	0.06	-	0.1	40
Pb	-	4E-05	4E-05	-	8E-05	0.6

[a] Based on Unit #2 operation at full load (100% load).
[b] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[c] Based on 8,760 hours of operation for two Water Bath Heaters.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

2.4.4 Toxic Air Pollution Sources Review

The permitting authority on the air discharge permit (ADP) application, SWCAA, requires a review of new or modified toxic air pollution sources as part of that application, per SWCAA 400-076 and Washington Administrative Code (WAC) Chapter 173-460. The air toxics program uses a tiered review approach for regulating toxic air pollutant (TAP) emissions increases that are greater than de minimis levels. The regulations under WAC 173-460-060 also require the use of the "toxics Best Available Control Technology" (tBACT) for emission control on new or modified sources where emissions exceed de minimis thresholds. The first-tier review, outlined in WAC 173-460-080, involves evaluating the aggregate potential emissions increase of each TAP in an acceptable source impact analysis. The acceptable source impact analysis involves either comparing the increase in emissions against established small quantity emission rates (SQER) or comparing the increase in impact at any location outside of property boundaries against the Acceptable Source Impact Levels (ASILs). The current de minimis, SQER, and ASIL limits are listed in WAC 173-460-150. SWCAA additionally requires an acceptable source impact analysis to be conducted for first tier review based on the 1998 version of the WAC 173-460-080 air toxic rules. The 1998 rules have different SQER and ASIL values and do not have de minimis levels. In some cases, the 1998 rules regulate different TAPs than the current regulation. To show TAP emissions are below ASILs, dispersion modeling is required.

The first-tier review determines if the TAP source meets health-based standards without requiring additional review. If the TAP is below either the SQER or the ASIL threshold, that TAP shows an acceptable source impact and has passed the first-tier review. If compliance cannot be demonstrated in this first tier, the source may be subject to a second-tier review, which involves more detailed analysis and possibly stricter controls. A third-tier review may be conducted if further evaluation is needed.

The Project's cumulative potential increase in TAP emissions from the new and modified sources were quantified and compared to the limits in the current and the 1998 version of the WAC 173-460-080 air toxic rules. It should be noted that TAP emissions reductions from past baseline operations for Unit #2 combusting coal were taken into account for NO_2, CO, SO_2, and H_2SO_4.[1] Cumulative emissions from these four TAPs will decrease as a result of the Project. Therefore, they are not included in the acceptable source impact analysis. Aside from these four TAPs, pollutant reductions from the Unit #2 baseline were not considered and the acceptable source impact analysis is expected to be a conservative proposal for certain TAPs.

2.4.4.1 Toxic Air Pollutants to Model Based on Current Air Toxic Rules

The first-tier review of TAPs based on the current WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to de minimis thresholds. Table 2-4 shows Project TAPs that are below their respective de minimis limits. The remaining significant TAPs were then compared to the SQER thresholds. Table 2-5 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-6 lists the project's TAP emissions that exceed SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-4. TransAlta Project De Minimis TAP Emissions

[1] The Unit #2 emissions reductions from baseline are discussed at length in the ADP application narrative with respect to PSD applicability.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	De Minimis Threshold	Proposed Emissions Less than De Minimis?
Chrysene	218-01-9	lb/year	6.4E-02	4.5E-01	Yes
Toluene	108-88-3	lb/24-hr	5.7E-01	1.9E+01	Yes
Copper	7440-50-8	lb/1-hr	5.9E-03	9.3E-03	Yes
Selenium	7782-49-2	lb/24-hr	4.0E-03	7.4E-02	Yes

Table 2-5. TransAlta Project SQER TAP Emissions

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	SQER Threshold	Proposed Emissions Less than SQER?
Benz(a)anthracene	56-55-3	lb/year	6.4E-02	8.9E-01	Yes
Benzo(a)pyrene	50-32-8	lb/year	4.2E-02	1.6E-01	Yes
Benzo(b)fluoranthene	205-99-2	lb/year	6.4E-02	8.9E-01	Yes
Benzo(k)fluoranthene	207-08-9	lb/year	6.4E-02	8.9E-01	Yes
Dibenzo(a,h)anthracene	53-70-3	lb/year	4.2E-02	4.1E-03	Yes
Indo(1,2,3-cd)pyrene	193-39-5	lb/year	6.4E-02	8.9E-01	Yes
Chromium III	7440-47-3	lb/24-hr	1.9E-01	3.7E-01	Yes

Table 2-6. TransAlta Project TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m^3)
3-Methylcholanthrene	56-49-5	lb/year	6.4E-02	9.6E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	lb/year	5.7E-01	8.5E-06
Benzene	71-43-2	lb/year	1.0E+02	1.3E-01
Dichlorobenzene	106-46-7	lb/year	4.2E+01	9.1E-02
Formaldehyde	50-00-0	lb/year	8.1E+03	1.7E-01
n-Hexane	110-54-3	lb/24-hr	3.0E+02	7.0E+02
Naphthalene	91-20-3	lb/year	1.8E+02	2.9E-02
Silica	7631-86-9	lb/24-hr	4.2E+00	3.0E+00
Arsenic	7440-38-2	lb/year	8.2E+01	3.0E-04
Beryllium	7440-41-7	lb/year	5.9E+01	4.2E-04
Cadmium	7440-43-9	lb/year	7.9E+01	2.4E-04
Chromium VI	18540-29-9	lb/year	1.5E+01	4.0E-06
Cobalt	7440-48-4	lb/24-hr	1.4E-02	1.0E-01
Lead	7439-92-1	lb/year	1.9E+02	8.3E-02
Manganese	7439-96-5	lb/24-hr	5.8E-01	3.0E-01
Mercury	7439-97-6	lb/24-hr	3.0E-01	3.0E-02
Nickel	7440-02-0	lb/year	9.6E+01	3.8E-03
Vanadium	7440-62-2	lb/24-hr	3.8E-01	1.0E-01

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

2.4.4.2 Toxic Air Pollutants to Model Based on 1998 Air Toxic Rules

The first-tier review of TAPs based on the 1998 version of the WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to SQER thresholds. Table 2-7 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-8 lists the project's TAP emissions that exceed 1998 SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-7. TransAlta Project 1998 SQER TAP Emissions

Toxic Air Pollutant	CAS #	Project Potential Emissions Totals (lb/hr)	Project Potential Emissions Totals (lb/yr)	SQER Threshold (lb/hr)	SQER Threshold (lb/yr)	Proposed Emissions Less than SQER?
Naphthalene	91-20-3	4.2E-03	22	2.6	22,750	Yes
Toluene	108-88-3	2.4E-02	120	5.0	42,748	Yes
Chromium III	7440-47-3	8.0E-03	41	0.02	175	Yes
Cobalt	7440-48-4	5.8E-04	3	0.02	175	Yes
Copper	7440-50-8	5.9E-03	30	0.02	175	Yes
Lead	7439-92-1	3.5E-03	18	-	50	Yes
Manganese	7439-96-5	2.6E-03	13	0.02	175	Yes
Mercury	7439-97-6	1.8E-03	9	0.02	175	Yes
Selenium	7782-49-2	1.7E-04	1	0.02	175	Yes
Vanadium	7440-62-2	1.6E-02	81	0.02	175	Yes

Table 2-8. TransAlta Project 1998 TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m³)
Benzene	71-43-2	lb/year	7.4E+01	1.2E-01
Formaldehyde	50-00-0	lb/year	2.7E+03	7.7E-02
n-Hexane	110-54-3	lb/24-hr	3.0E+02	2.0E+02
Arsenic	7440-38-2	lb/year	7.1E+00	9.6E-05
Beryllium	7440-41-7	lb/year	4.2E-01	8.5E-06
Cadmium	7440-43-9	lb/year	3.9E+01	1.3E-01
Chromium VI	18540-29-9	lb/year	8.9E+00	9.1E-02
Nickel	7440-02-0	lb/year	7.4E+01	1.7E-01
PAH as benzo(a)pyrene	50-32-8	lb/year	7.3E-02	7.0E+02

3.0 AIR QUALITY IMPACT ASSESSMENT METHODOLOGY

3.1 Introduction

The dispersion modeling analyses for the Project was conducted in accordance with the USEPA's *Guideline on Air Quality Models* (USEPA 2024a), as supplemented by additional agency guidance. The modeling methodology was described in an *Air Quality Dispersion Modeling Protocol* (Tetra Tech, 2025), which was submitted to and approved by WDOE (WDOE also provided support with respect to

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

the SWCAA-relevant components, the air toxics and the non-PSD pollutants). It should be noted that the Project has changed to only natural gas firing in Unit #2 and therefore the Project emissions have been updated accordingly.

As described in Section 2.4.3, the Project triggers a PSD major modification for VOC, due to the significant net emissions of that pollutant. CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2 are not subject to PSD review because the Project emissions did not exceed the PSD SERs for those pollutants, and therefore, these pollutants are not subject to the specific PSD modeling requirements. As a result, dispersion modeling was conducted for CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2, to demonstrate compliance with the NAAQS as required under SWCAA 400-110(3)(c). As there is no NAAQS for VOC, this pollutant was not subject to dispersion modeling requirements, however it is considered in the NAAQS demonstration for secondary O_3.

The dispersion modeling for the Project evaluated worst-case operating conditions associated with a 59% capacity factor at full load to predict the appropriate maximum ground-level concentration for each pollutant and averaging period. The appropriate maximum concentrations from the worst-case scenarios are compared to the significant impact levels (SILs). If the maximum concentration is below the corresponding SILs, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a cumulative impact analysis was conducted with ambient background concentrations that include other major emission sources in the area. The modeled impacts are added to ambient monitored background concentrations and the sum compared to the NAAQS. Table 3-1 provides the SILs and NAAQS, as well as the modeling rank basis, as defined by USEPA, used for the assessment of compliance with the various criteria.

Table 3-1. SILs and NAAQS

Pollutant	Averaging Period	Rank for SIL Assessment	SIL (µg/m³)	Rank for NAAQS Assessment	NAAQS (µg/m³)
NO_2	1-hour	H1H [a] (5-year average)	7.5	H8H [b] (5-year average)	188
	Annual	H1H	1	H1H	100
CO	1-hour	H1H	2,000	H2H [c]	40,000
	8-hour	H1H	500	H2H	10,000
PM_{10}	24-hour	H1H	5	H6H [d] over 5 years	150
$PM_{2.5}$	24-hour	H1H (5-year average)	1.2 [e]	H8H (5-year average)	35
	Annual	H1H (5-year average)	0.13 [e]	H1H (5-year average)	9
SO_2	1-hour	H1H	7.8	H4H (5-year average)	196
	Annual	H1H	1	H1H (5-year average)	26.2

[a] Highest first-high concentration
[b] Highest eighth-high concentration
[c] Highest second-high concentration
[d] Highest sixth-high concentration
[e] Use of SILs can be justified using ambient monitoring data, see text below.

The $PM_{2.5}$ SILs at 40 CFR 52.21(k)(2) and 40 CFR 51.165(k)(2) were vacated and remanded by the January 22, 2013 United States Court of Appeals for the District of Columbia Circuit Decision on a Sierra Club v. USEPA case. The $PM_{2.5}$ SILs that were vacated and remanded concerned portions of the

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

$PM_{2.5}$ SIL regulations that automatically exempted sources from further analyses for demonstration of compliance with NAAQS and PSD increments if the predicted $PM_{2.5}$ impacts were less than the $PM_{2.5}$ SILs. The January 22, 2013 Decision specifically did not vacate the $PM_{2.5}$ SILs at 40 CFR 165(b)(2), which provides that a major source or major modification will be considered to cause or contribute to a violation of the NAAQS when such source or modification is predicted to exceed the SIL at any locality that does not or would not meet the applicable NAAQS. Under USEPA modeling guidance issued subsequent to this January 22, 2013 Decision, $PM_{2.5}$ SILs may still be used to justify permitting decisions for $PM_{2.5}$ NAAQS and increment compliance if appropriate justification is provided that the use of such SILs is protective of NAAQS and increment compliance. For NAAQS demonstrations, a key portion of this justification typically would include demonstrating that a large margin exists between the ambient background and the standard. As shown in Section 3.8 of this Protocol, existing ambient monitoring data representative of ambient background for the Project site and surrounding area indicate that there is a substantial margin between the ambient background levels and the NAAQS (see Table 3-6). Therefore, predicted Project impacts below the respective SILs will allow for adequate protection of the NAAQS, leaving considerable margin for contributions from other interacting sources.

3.2 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year) and will be limited to that 59% capacity;
- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) water bath heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

Table 3-2 summarizes the physical stack characteristics modeled for the NAAQS analysis. Detailed emissions and source parameter data are provided in Table 3-3. The Unit #2 boiler was modeled at full load (100% load or 723 MW) and minimum stable load (190 MW) to determine which scenario resulted in the worst-case predicted impacts[2]. Then the worst-case Unit #2 scenario was modeled in combination with the auxiliary boiler, dew point heaters and cooling towers to determine total Project impacts for the NAAQS modeling analysis. The conversion of NO_X emission rates to modeled NO_2 concentrations employed the Tier 2 Ambient Ratio Method (ARM2) NO_X to NO_2 conversion assumptions.

[2] Startup and shutdown impacts were evaluated and studied for Unit #2. Based on those evaluations, combustion emissions are anticipated to be consistent across a lb/MMBtu basis, as in when the amount of fuel combusted decreases, the emissions associated with fuel combustion would also decrease. Therefore, the VOC emissions expressed in lb/MMBtu account for the startup and shutdown emissions without further need for clarification or allowances. The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 3-2. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
U2_100	Unit #2 Boiler (100% load)	510831.55	5177972.72	68.12	140.21	7.32
U2_190MW	Unit #2 Boiler (190 MW)	510831.55	5177972.72	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	510761.14	5178008.60	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	510404.72	5177875.40	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	510405.42	5177866.41	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	510533.56	5177641.83	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	510534.41	5177654.90	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	510534.92	5177668.14	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	510535.60	5177680.53	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	510536.28	5177695.13	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	510537.13	5177708.37	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	510544.53	5177640.47	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	510544.87	5177653.54	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	510545.38	5177666.78	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	510546.06	5177679.17	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	510546.74	5177693.77	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	510547.59	5177707.01	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	510638.31	5177504.10	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	510629.05	5177513.44	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	510619.50	5177523.28	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	510610.29	5177533.36	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	510600.63	5177543.17	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	510591.37	5177552.48	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	510630.64	5177496.41	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	510621.64	5177506.20	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	510612.30	5177515.69	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	510602.94	5177525.64	93.96	19.91	7.62

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
COOLT2_K	Cooling Tower 2 Cell K	510593.39	5177535.37	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	510584.10	5177544.87	93.96	19.91	7.62

[a] UTM Zone 10, WGS-84 datum

Table 3-3. Stack Exhaust Parameters and Emission Rates

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
U2_100	441.48	29.77	141.747	103.948	61.331	6.488	3.828	6.488	3.828	0.679	0.400
U2_190MW	388.71	9.55	47.797	35.051	35.052	2.188	2.188	2.188	2.188	0.229	0.229
AUXBLR	422.04	11.73	0.695	0.282	0.042	0.129	0.019	0.129	0.019	0.013	0.002
DPH_1	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
DPH_2	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
COOLT1_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
COOLT2_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

[a] UTM Zone 10, WGS-84 datum.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.3 Model Selection

The USEPA-recommended AERMOD modeling system (USEPA 2024b) was used to conduct the dispersion modeling. The current versions of the model (AERMOD version 24142, AERMET version 24142 and AERMAP version 24142) were used to model criteria and toxic pollutants.

3.4 Meteorological Data for AERMOD

AERMOD was run in refined mode with five years (2020-2024) of hourly surface meteorological data collected at the Olympia Regional Airport meteorological station in Thurston, Washington, along with corresponding upper air data collected at McNary Field Airport in Salem, Oregon. These data were processed using the AERMET program (v24142) along with the associated programs AERMINUTE (v15272) and AERSURFACE (v20060). AERSURFACE was run based on land use data around the meteorological data collection site (Olympia Regional Airport) and considered 12 equal 30-degree sectors. The following seasonal variations were assigned:

- Winter (no snow): December, January, and February
- Transitional Spring: March, April, and May
- Midsummer: June, July, and August
- Autumn: September, October, and November

The monthly moisture conditions (average, wet, or dry) were determined for each year based on precipitation data measured in Centralia, Washington with missing data filled in from Olympia, Washington. The moisture conditions for each month were input to AERSURFACE to determine surface characteristics and results were input to AERMET for meteorological data processing. Default settings were used for the AERMET processing including the adjustment of truncated 1-minute ASOS winds. A minimum wind speed threshold of 0.5 m/s and the friction velocity adjustment (adj_u*) option were used.

A joint frequency distribution of the winds (wind rose) for the five years of meteorological data used in the AERMOD modeling analysis is presented in Figure 3-1. The predominant winds are also the strongest winds and they are from the south through southwest sector.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

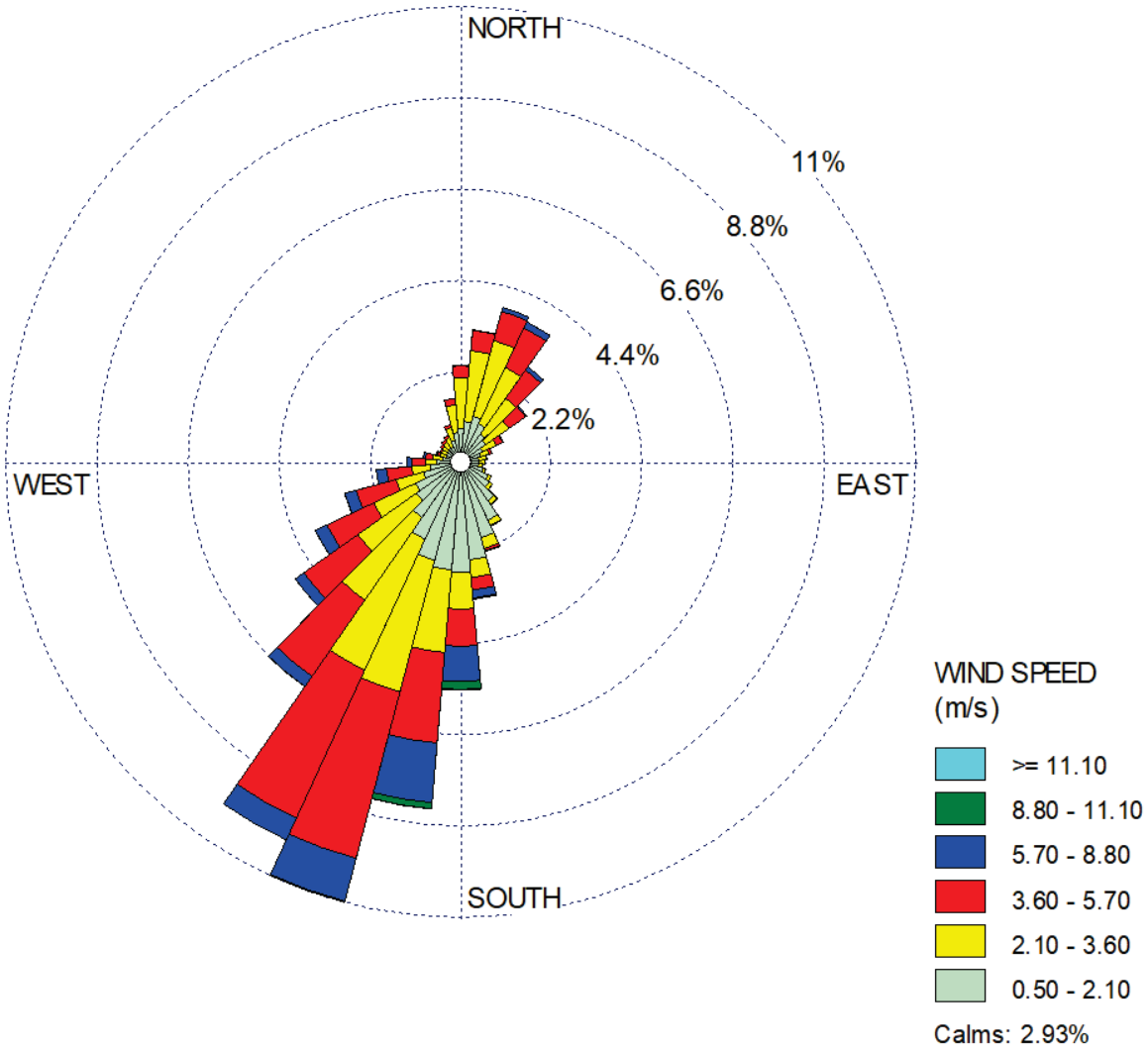


Figure 3-1. Five-year (2020-2024) Wind Rose of Wind Measurements at Olympia Meteorological Station

3.5 Land Use

It is necessary to determine whether the land-use pattern in the environs of a Project is urban or rural for modeling purposes. A land use determination has been made following the classification technique suggested by Auer (1978) in accordance with USEPA modeling guidance. The classification determination was conducted by assessing land-use categories within a 3-kilometer (km) radius of the proposed site. Figure 3-2 provides a section of an aerial photograph with the 3-km radius around the Project Site shown. Inspection of aerial photography indicates that the majority of the area is rural, with urban land uses (i.e., industrial, commercial, and dense residential) comprising less than 50% of the area within a 3 km radius. Therefore, rural dispersion coefficients were used for the air quality modeling analysis.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

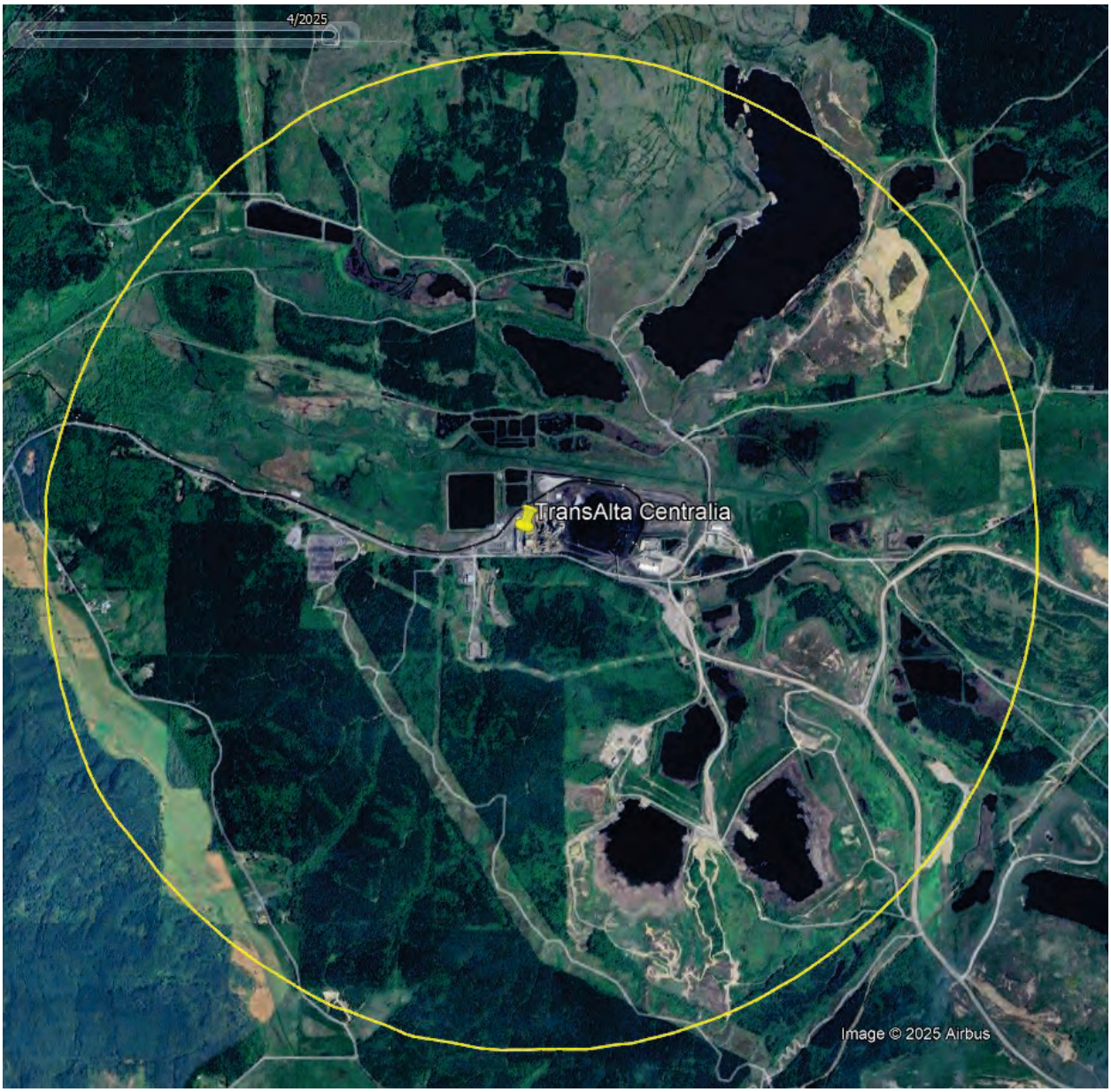


Figure 3-2. Urban / Rural Land Use Determination within a 3 km radius

3.6 Good Engineering Practice Stack Height Analysis

A GEP stack height analysis was performed based on the Project and Facility structures to determine the potential for building-induced aerodynamic downwash for the stacks. The analysis procedures described in USEPA's Guidelines for Determination of Good Engineering Practice Stack Height (USEPA 1985) guidance and included in SWCAA 400-200 Creditable Stack Height regulations were used.

The "GEP stack height" is defined as the greater of 65 meters or the formula height. The "formula height" is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground-level concentrations at a closer proximity than would

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided.

The GEP formula stack height, as defined in the 1985 final regulation, is calculated as follows:

$$H_{GEP} = H_{BLDG} + 1.5L$$

Where:

- H_{GEP} is the calculated GEP formula height;
- H_{BLDG} is the height of the nearby structure; and
- L is the lesser dimension (height or projected width) of the nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto the plane perpendicular to the direction of the wind. The GEP stack height is based on the plane projection of any structure that results in the greatest calculated height. For the purpose of the GEP analysis, nearby refers to the "sphere of influence" defined as 5 times L (the lesser dimension – height or projected width – of the nearby structure), downwind from the trailing edge of the structure.

The USEPA's Building Profile Input Program (BPIP-Prime, v04274) that is appropriate for use with the PRIME algorithms in AERMOD was used. The building dimensions and coordinates for each potentially influencing structure was input to BPIP-Prime to determine direction-specific building dimension data for input to AERMOD.

If the stack heights are below their calculated GEP height, the exhaust emissions will experience the aerodynamic effects of downwash. As determined by BPIP-Prime, all of the stack heights are below their calculated GEP height. For each stack, the controlling structures differ by direction, and wind-direction specific building dimensions are generated by BPIP-Prime for input to AERMOD. AERMOD accounts for potential downwash from nearby structures in the dispersion calculations. The PRIME algorithms in AERMOD calculate the dimensions of the structure's wake, from the cavity immediately downwind of the structure to the far wake.

3.7 Receptor Grid and AERMAP Processing

Discrete receptors were placed at 12.5-meter intervals along the Facility fence lines. There will be two fences, one surrounding the generation area of the plant and one surrounding the cooling towers across the road from the generation area. The WDOE recommended[3] a nested receptor grid with spacing as follows:

- At 12.5-meter intervals to 150 meters;
- At 25-meter intervals from 150 meters to 400 meters;
- At 50-meter intervals from 400 meters to 900 meters;
- At 100-meter intervals from 900 meters to 2,000 meters;
- At 300-meter intervals from 2,000 meters to 4,500 meters; and

[3] Email communication from Beth Friedman (WDOE) to Liz Hendrick (Tetra Tech) on 3/4/2025.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

- At 600-meter intervals from 4,500 meters to 10,000 meters.

The spacing recommendations were followed; however, because the Project involves multiple emission sources at different locations, the nested grid was extended to at least 150 meters beyond the bounding box of the sources. Per Section 9.2.2 of 40 CFR Part 51, higher-resolution receptor grids (50m spacing) will be used at predicted maxima located within coarser grid areas. Figure 3-3 shows the full nested Cartesian receptor grid including a refined grid that was used for annual NO_2 and toxics modeling. A zoomed-in view of the inner grids is provided in Figure 3-4.

Terrain elevations at receptors were obtained using Lake Environmental's AERMOD View program and United States Geological Survey (USGS) digital terrain data. AERMOD View implements the AERMAP model, which includes processing routines that extract National Elevation Data (NED) at 10-meter spacing based on North American Datum of 1983 (NAD83). The four nearest data points surrounding each receptor are used to determine receptor terrain elevations (by interpolation) for air quality model input. At WDOE's request, each receptor was assigned a flagpole height of 1.5 meters above the ground.

3.8 Ambient Background Data

Based on the recommendation of Washington WDOE, model and monitoring data from July 2014 through June 2017 were used to estimate background concentrations of criteria air pollutant design values for use in air permit analysis. The tool located at Background Concentrations 2014 - 2017 facilitates the retrieval and exploration of the estimated design values at user-specified locations in Washington, Idaho, and Oregon. These values are assumed to be inclusive of the emissions from constantly emitting surrounding sources including the coal-fired emissions from TransAlta Centralia. This results in a conservative estimate of ambient background because coal-firing at TransAlta Centralia will cease in December 2025. Significant wildfire smoke and windblown dust events have mostly been filtered out. In general, WDOE recommends using the highest value at the grid cell close to your project site as representative background concentrations. The grid cell across the road from the TransAlta Centralia Station (latitude 46.75 °N, Longitude 122.85 °W) was used. The selected representative ambient air quality background concentrations are summarized in Table 3-4.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

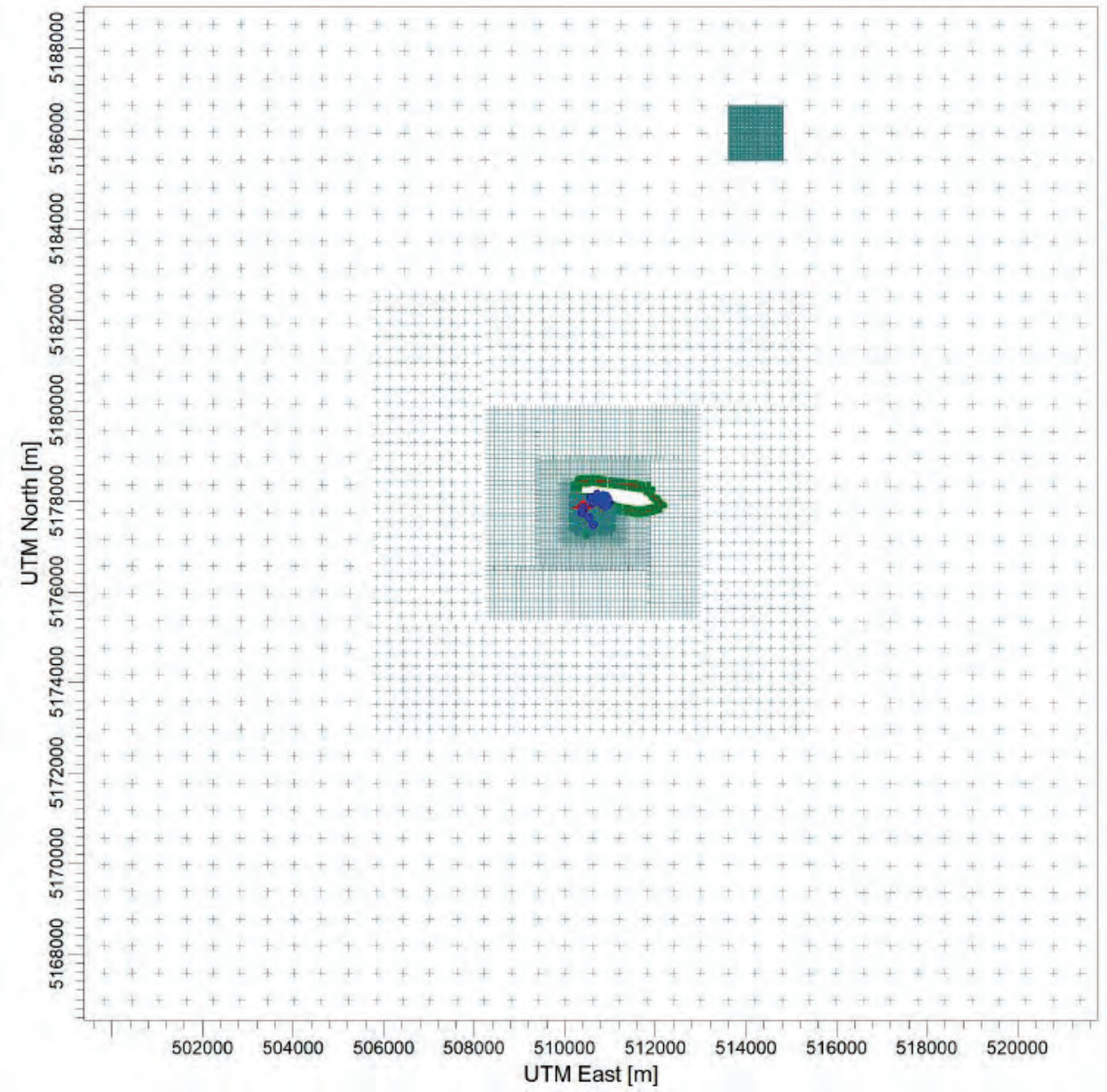


Figure 3-3. Full Nested Cartesian Receptor Grid including the Refined Receptor Grid

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

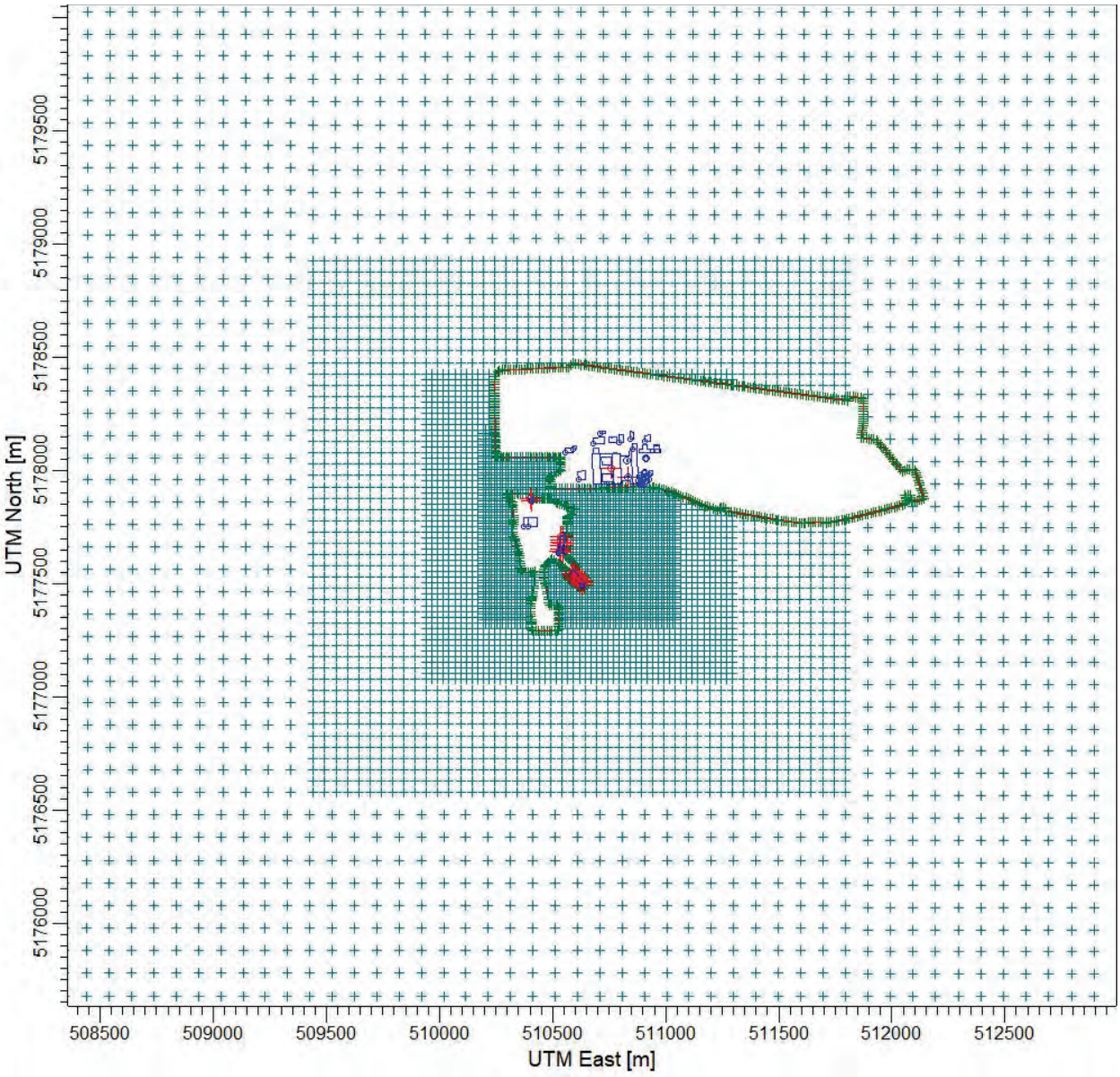


Figure 3-4. Zoomed to Inner Grids of the Nested Cartesian Receptor Grid

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 3-4. Proposed Air Quality Background Concentrations

Pollutant	Averaging Period	Grid Cell[a]	Background Conc.		
			ppm	ppb	µg/m³
CO	1-hour	A	1.07		1,241.20
	8-hour	A	0.72		835.20
NO_2	1-hour	A		27.60	51.89
	Annual	A		6.2	11.66
PM_{10}	24-hour	A			43.70
$PM_{2.5}$	24-hour	A			17.80
	Annual	A			6.00
SO_2	1-hour	A		5.2	13.62
	24-hour	A		2.4	6.29
	Annual	A		0.5	1.31
O_3	8-hour	A		54	106.01

[a] Grid Cell across the Road from TransAlta Centralia Station (Latitude 46.75 º N, Longitude 122.85 º W).

Table 3-5 presents the difference between the NAAQS and the representative background concentration, compared to the SILs. As shown in Table 3-5, all averaging periods for each pollutant have a margin between the monitored value and the NAAQS that is greater than the respective SIL; therefore, use of the SILs as *de minimis* levels for all pollutants is appropriate.

Table 3-5. Margin between Ambient Air Quality Concentrations and the NAAQS

Pollutant	Averaging Period	Background Concentration (µg/m³)	NAAQS (µg/m³)	Margin (NAAQS-Background) (µg/m³)	Significant Impact Level (µg/m³)
CO	1-Hour	1241.2	40,000	38,758.8	2,000
	8-Hour	835.2	10,000	9,164.8	500
NO_2	1-Hour	51.89	188	136.1	7.5
	Annual	11.66	100	88.3	1
PM_{10}	24-Hour	43.7	150	106.3	5
$PM_{2.5}$	24-Hour	17.8	35	17.2	1.2
	Annual	6.0	9	3.0	0.2
SO_2	1-Hour	13.62	196	182.4	1.2
	Annual	1.31	26.2	24.9	0.2
O_3	8-Hour	54 ppb	70 ppb	16 ppb	1 ppb

3.9 Modeling Methodology

The modeling analyses were conducted using the most current version of AERMOD (v24142) along with the meteorological data as described in Section 3.4. The analysis was conducted to demonstrate compliance with the NAAQS. The worst-case Unit #2 boiler operating condition was evaluated and modeled with other project sources as described in Section 3.2 to assess compliance with the NAAQS. If the maximum concentrations from any Project criteria pollutant emissions were predicted to be equal to or greater than their respective SILs, shown in Table 3-1, a modeling analysis including ambient background concentrations was conducted to determine compliance with the NAAQS.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.9.1 NO_2 Modeling Methods

The NO_2 impact analysis was consistent with the EPA guidance on 1-hour NO_2 dispersion modeling, Guideline on Air Quality Models (EPA 2024a). The 2024 EPA guidance describes a multi-tiered screening approach for modeling 1-hour NO_2. The key issue is that NO_X emissions are released primarily in the form of nitric oxide, which convert to NO_2 in the atmosphere. Tier 1 in the screening approach assumes that all NO_X converts to NO_2. Tier 2 assumes NO_X converts to NO_2 at a rate consistent to an appropriate NO_2/NO_X ambient ratio derived from ambient measurement data. Tier 2 ARM2 method is a regulatory default conversion approach in AERMOD.

The Tier 2 ARM2 conversion methodology was used with the default minimum (0.5) and maximum (0.9) NO_2/NO_X ratios.

3.10 Assessment of Secondary Particulate and Ozone

The analysis of $PM_{2.5}$ impacts is consistent with the *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (USEPA 2022). If the Project has an annual potential to emit (PTE) of direct $PM_{2.5}$, NO_x, or SO_2 greater than their respective SER thresholds, air quality impacts from both primary and secondary $PM_{2.5}$ emissions must be assessed. For this Project, $PM_{2.5}$ and NO_x emissions are greater than their respective SERs, triggering the secondary $PM_{2.5}$ analysis. Impacts of primary $PM_{2.5}$ emissions were determined with dispersion modeling using AERMOD, as described above.

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in the 2024 *EPA Guideline on Air Quality Models*. This guideline promulgated a two-tier approach for addressing single-source impacts on 8-hour O_3 and 24-hour and annual secondary $PM_{2.5}$. A Tier 1 analysis was used, which involves the use of technically credible relationships between precursor emissions and secondary ambient impacts based on existing modeling studies deemed sufficient for evaluating a project source's impacts. Specifically, USEPA modeling described in the *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (USEPA 2019) was used. USEPA has generated empirical relationships between single sources and O_3 and $PM_{2.5}$ impacts for hundreds of hypothetical sources that vary in stack height, emission rate, and geographic location. The MERPs View Qlik application tool[4] was used. The tool provides illustrative hypothetical single-source modeled impacts for annual and daily maximum average $PM_{2.5}$ and annual maximum daily 8-hour O_3 for use in NAAQS Tier 1 demonstrations. The sources represented "high" releases (90 meters) and "low" releases (10 meters) at multiple emissions levels. For this Project, the high-level stack scenario is most appropriate because the Project Unit #2 stack height is 140.2 meters. Hypothetical sources were evaluated by USEPA at three geographic locations in Washington state; Klickitat in south central Washington approximately 168 km southeast of the Project site, Skagit located approximately 184 km north-northeast of the Project and situated along the bay, and Spokane which is approximately 425 km away in the eastern part of the state. The most representative hypothetical source for this Project is the Klickitat, Washington site. It is the closest to the Project site and the environment surrounding the Klickitat area is most like the Centralia area. Therefore, the Project estimates the expected secondary

[4] Located at https://www.epa.gov/scram/merps-view-qlik.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

$PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The hypothetical modeling results are scaled by the ratio of the USEPA scenario emission rate to the Project emission rate for each pollutant. The contributions to secondary $PM_{2.5}$ formation from the precursor emissions of NO_X and SO_2 are summed to estimate the total secondary $PM_{2.5}$. Total $PM_{2.5}$ impacts include the primary modeled $PM_{2.5}$ plus the estimated secondary $PM_{2.5}$ formed from precursor emissions.

Chemical transformations of NO_x and VOC contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional emissions. Section 5.3 of the *Guideline on Air Quality Models* recommends a two-tiered approach for an ambient O_3 analysis (USEPA 2024a). For this Project, NO_x and VOC emissions are greater than their respective SERs, triggering the requirement for an analysis of secondary formation of ozone. Like the analysis for secondary $PM_{2.5}$, a Tier 1 demonstration for O_3 formation was scaled from the existing USEPA modeling from the Klickitat site which was obtained using the MERPs View Qlik tool. To demonstrate the effect of Project emissions on regional O_3 levels, the estimated secondary formation of O_3 are compared to the USEPA 8-hour O_3 SIL, and if necessary, ambient background will be added to the secondary O_3 concentration for a NAAQS compliance demonstration.

3.11 Toxic Air Pollutant Source Impact analysis

Consistent with the first-tier review specified in both the current and 1998 version of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4 were evaluated with modeling. TAPs were modeled with AERMOD for each source that emits any of the eighteen TAPs that are being evaluated under the current rule and ten TAPs that are being evaluated under the 1998 rule. The AERMOD modeling was based on a unit emission rate of 1 gram/second (g/s). Then the TAP emission rates for each pollutant for each source were multiplied by modeled maximum normalized concentrations (assuming 1 g/s emission rates) and the contribution from each source summed to calculate a total impact concentration for each pollutant. This methodology is conservative because it sums all individual maximum impacts for a specific TAP for comparison with the ASIL thresholds regardless of where or when each maximum is predicted. The maximum predicted impacts from each source will likely not occur at the same time or at the same location. If this unit analysis shows noncompliance with the ASIL for any specific TAP, the TAP(s) were then modeled separately with specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact. This approach ensures that modeled impacts are not overestimated when compared to the ASIL.

4.0 AIR QUALITY MODELING RESULTS

4.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NO_x

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

and SO_2 emission are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NO_x and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of both natural gas and ultra low sulfur diesel fuel in Unit #2 (with worst-case impacts being modeled for each respective pollutant). The diesel usage was later eliminated from the project and Unit #2 will now only fire natural gas. This report includes the air dispersion modeling from that natural gas combustion and its associated impacts.

4.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2 and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios are provided in Appendix A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS and toxics modeling analyses.

4.3 Secondary Pollutant Assessment

4.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily (24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NO_x and SO_2 based on the USEPA photochemical modeling. The most representative USEPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The following calculations are used to estimate the Project only secondary $PM_{2.5}$ impacts.

For 24-hour secondary $PM_{2.5}$,

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

- NO_x – 3,000 tons/year (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.177 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.177 µg/m^3= 0.126 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.233 µg/m^3
  - Project SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.233 = 0.007 µg/m^3

Total 24-hour secondary $PM_{2.5}$ impact due to Project = 0.126 + 0.007 = **0.133 µg/m^3**

For annual secondary $PM_{2.5}$,

- NO_x – 3.000 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0084 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.0084 µg/m^3= 0.0060 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0086 µg/m^3
  - Facility SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.0086 = 0.0002 µg/m^3

Total annual secondary PM2.5 impact due to Project = 0.0060 + 0.0002 = 0.0062 µg/m3

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

4.3.2 Ozone Ambient Impact Assessment

Chemical transformation of NO_x and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing USEPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NO_x and VOC based on the USEPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the USEPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NO_x emissions and 500 tpy of VOC precursor emissions. The following calculations are used to estimate the Project only O_3 impacts.

- NO_x – 3,000 tpy (90 m source), Klickitat 8-hour O_3 impact = 7.954 ppb
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated O_3 impact due to Project = (2,134.7 /3000) * 7.954 ppb = 5.660 ppb
- VOC - 500 tpy (90 m source), Klickitat 8-hour O_3 impact = 0.031 ppb

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

- Project VOC emissions = 59.06 tpy
- Estimated O_3 impact due to Project = (59.06 /500) * 0.031 ppb = 0.004 ppb

Total 8-hour O3 impact = 5.660 + 0.004 = 5.664 ppb

4.4 Project Impacts Compared to the SILs

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 4-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 4-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

Table 4-1. SILs Analysis Results

Pollutant	Averaging Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	98.49[c]	7.5
	Annual	H1H	1.14[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	1.86 c	1.2
	Annual	H1H (5-year average)	0.26 c	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	5.66 ppb c	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

4.5 NAAQS Analysis

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

representative ambient background concentrations (as described in Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 4-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 4-2 are shown in contour plots provided in Appendix B.

Table 4-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117. 98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

4.6 Toxic Air Pollutant Modeling Results

Consistent with the first-tier review specified in both the current and 1998 versions of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4, Tables 2-6 and 2-8, were evaluated with AERMOD modeling. As described in Section 3.11, the modeling was first conducted based on a unit emission rate in a conservative unit analysis. Individual TAP modeling was conducted if the unit analysis showed noncompliance with the ASIL for any specific TAP, so as not to overestimate the TAP cumulative impacts. It should be noted that the refined receptor grid for annual impacts was incorporated into the toxics modeling and that impacts from the highest scenario for Unit #2 (i.e., 190 MW) were included in the TAP analysis results.

Table 4-3 shows the modeling results for the eighteen TAPs modeled for the current rule compared to the current ASILs. All TAPs demonstrate compliance with their respective ASILs. Individual TAP modeling was conducted for one TAP, Chromium VI. Chromium VI was the TAP closest to their ASIL at 79%. The next TAP closest to their ASIL is Silica, at 23% of its ASIL. Additionally, Silica's impact is expected to be lower than is shown in Table 4-3 because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 4-3 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
3-Methylcholanthrene	56-49-5	year	9.6E-05	4.7E-08	0%	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	year	8.5E-06	4.2E-07	5%	Yes
Benzene	71-43-2	year	1.3E-01	5.5E-05	0%	Yes
Dichlorobenzene	106-46-7	year	9.1E-02	3.1E-05	0%	Yes
Formaldehyde	50-00-0	year	1.7E-01	2.0E-03	1%	Yes
n-Hexane	110-54-3	24-hr	7.0E+02	1.5E+00	0%	Yes
Naphthalene	91-20-3	year	2.9E-02	1.6E-05	0%	Yes
Arsenic	7440-38-2	year	3.0E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	2.4E-04	2.9E-05	12%	Yes
Chromium VI[b]	18540-29-9	year	4.0E-06	3.2E-06	79%	Yes
Cobalt	7440-48-4	24-hr	1.0E-01	6.9E-05	0%	Yes
Lead	7439-92-1	year	8.3E-02	1.3E-05	0%	Yes
Manganese	7439-96-5	24-hr	3.0E-01	3.1E-04	0%	Yes
Mercury	7439-97-6	24-hr	3.0E-02	2.1E-04	1%	Yes
Nickel	7440-02-0	year	3.8E-03	5.5E-05	1%	Yes
Vanadium	7440-62-2	24-hr	1.0E-01	1.9E-03	2%	Yes
Silica	7631-86-9	24-hr	3.0E+00	6.8E-01	23%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.
[b] Chromium VI was modeled individually with its specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact.

Table 4-4 shows the modeling results for the ten TAPs modeled for the 1998 rule compared to the 1998 ASILs. All TAPs demonstrate compliance with their respective ASILs. Chromium VI was the TAP closest to their ASIL at 8%. Note that all impacts shown in Table 4-4 are conservative because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Table 4-4 1998 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
Benzene	71-43-2	year	1.2E-01	5.5E-05	0%	Yes
Formaldehyde	50-00-0	year	7.7E-02	2.0E-03	3%	Yes
n-Hexane	110-54-3	24-hr	2.0E+02	1.5E+00	1%	Yes
Arsenic	7440-38-2	year	2.3E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	5.6E-04	2.9E-05	5%	Yes
Chromium VI	18540-29-9	year	8.3E-05	6.6E-06	8%	Yes
Nickel	7440-02-0	year	2.1E-03	5.5E-05	3%	Yes
Vanadium	7440-62-2	24-hr	1.7E-01	1.9E-03	1%	Yes
PAH as benzo(a)pyrene	50-32-8	year	4.8E-04	3.1E-08	0%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

5.0 REFERENCES

Auer, August H. 1978. “Correlation of Land Use and Cover with Meteorological Anomalies” *Journal of Applied Meteorology*, Volume 17. Pp. 636-643.

Tetra Tech Inc. 2025. *Air Quality Dispersion Modeling Protocol*. Tetra Tech, Inc., Boston, MA 02109. September, 2025.

USEPA. 1985. *Guideline for the Determination of Good Engineering Practice Stack Height* (Technical Support Document for the Stack Height Regulation) – Revised. EPA-450/4-80-023R, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

USEPA. 2019. *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program*. Richard A. Wayland Memorandum. Office of Air Quality Planning and Standards, Research Triangle Park, NC. April 30, 2019.

USEPA. 2022. *Guidance for Ozone and Fine Particulate Matter Permit Modeling*. EPA-454/R-22-005. Office of Air Quality Planning and Standards, Research Triangle Park, NC. July 29, 2022.

USEPA. 2024a. Guideline on Air Quality Models; Enhancements to the AERMOD Dispersion Modeling System. Codified in the Appendix W to 40 CFR Part 51. Federal Register Vol. 89, No. 230, November 29, 2024, Rules and Regulations.

USEPA, 2024b. *User’s Guide for the AMS/EPA Regulatory Model (AERMOD)*. EPA-454/B-24-007 (November 2024). Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX A: UNIT #2 LOAD ANALYSIS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Unit #2 Load Analysis		100%	190 MW
Stack Temperature	°F	335.0	240.0
Stack Mass Flow	acfm	2,651,430	850,074
Stack Diameter	ft	24	24
Stack Velocity	ft/s	97.7	31.3
Stack Temperature	K	441.5	388.7
Stack Diameter	m	7.32	7.32
Exhaust Velocity	m/s	29.77	9.55
Emissions, Annual			
NOx Emissions	tpy	2131.97	1218.47
CO Emissions	tpy	2907.23	1661.55
PM10 Emissions	tpy	133.06	76.05
PM2.5 Emissions	tpy	133.06	76.05
Sulfur Dioxide	tpy	13.92	7.96
Emissions, Short-term (g/s)			
NO_x	g/s	103.95	35.05
CO	g/s	141.75	47.80
PM_{10}	g/s	6.49	2.19
$PM_{2.5}$	g/s	6.49	2.19
SO_2	g/s	0.68	0.23
Emissions, Annual (g/s)			
NO_x	g/s	61.33	35.05
SO_x	g/s	0.40	0.23
PM_{10}	g/s	3.83	2.19
$PM_{2.5}$	g/s	3.83	2.19

UNIT IMPACT, chi/Q (ug/m^3 per g/s)		100%	190 MW
1-HR	1ST	0.63126	6.20683
8-HR	1ST	0.17836	3.08345
24-HR	1ST	0.07753	1.19912
1-HR	2ND	0.46679	6.20254
8-HR	2ND	0.15141	1.65954
24-HR	2ND	0.07569	0.73757
24-HR	6TH	0.06817	0.49674
ANNUAL	5-yr avg	0.01594	0.02831
ANNUAL Y1		0.01731	0.03220
ANNUAL Y2		0.01597	0.02836
ANNUAL Y3		0.01508	0.02637
ANNUAL Y4		0.01528	0.02624
ANNUAL Y5		0.01605	0.02862
Max. Indiv. Yr. Ann.		**0.01731**	**0.03220**

Worst Case Load Analysis - Unit 2 only (		100%	190 MW
1-hr NO_2 (full conversion)	H1H (5YA)	47.42412	135.7798
1-hr NO_2 (full conversion)	H8H (5YA)	40.84117	72.9494
Annual NO_2 (full conversion)	H1H	1.06	1.13
1-hr CO	H1H	89	297
1-hr CO	H2H	66	296
8-hr CO	H1H	25	147
8-hr CO	H2H	21	79
24-hr PM_{10}	H1H	0.50	2.62
24-hr PM_{10}	H6H	0.442	1.087
24-hr $PM_{2.5}$	H1H	0.45396	1.28112
24-hr $PM_{2.5}$	H8H	0.31579	0.45843
Annual $PM_{2.5}$	H1H (5YA)	0.06	0.06
1-hr SO_2	H1H (5YA)	0.30978	0.89097
1-hr SO_2	H4H (5YA)	0.28518	0.50281
24-hr SO2	H1H	0.05	0.27
24-hr SO2	H2H	0.05	0.17
Annual SO_2	H1H	0.007	0.007
Annual SO_2	H1H (5YA)	0.006	0.006

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX B: PROJECT PREDICTED CONCENTRATION CONTOURS FOR NAAQS ANALYSES

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

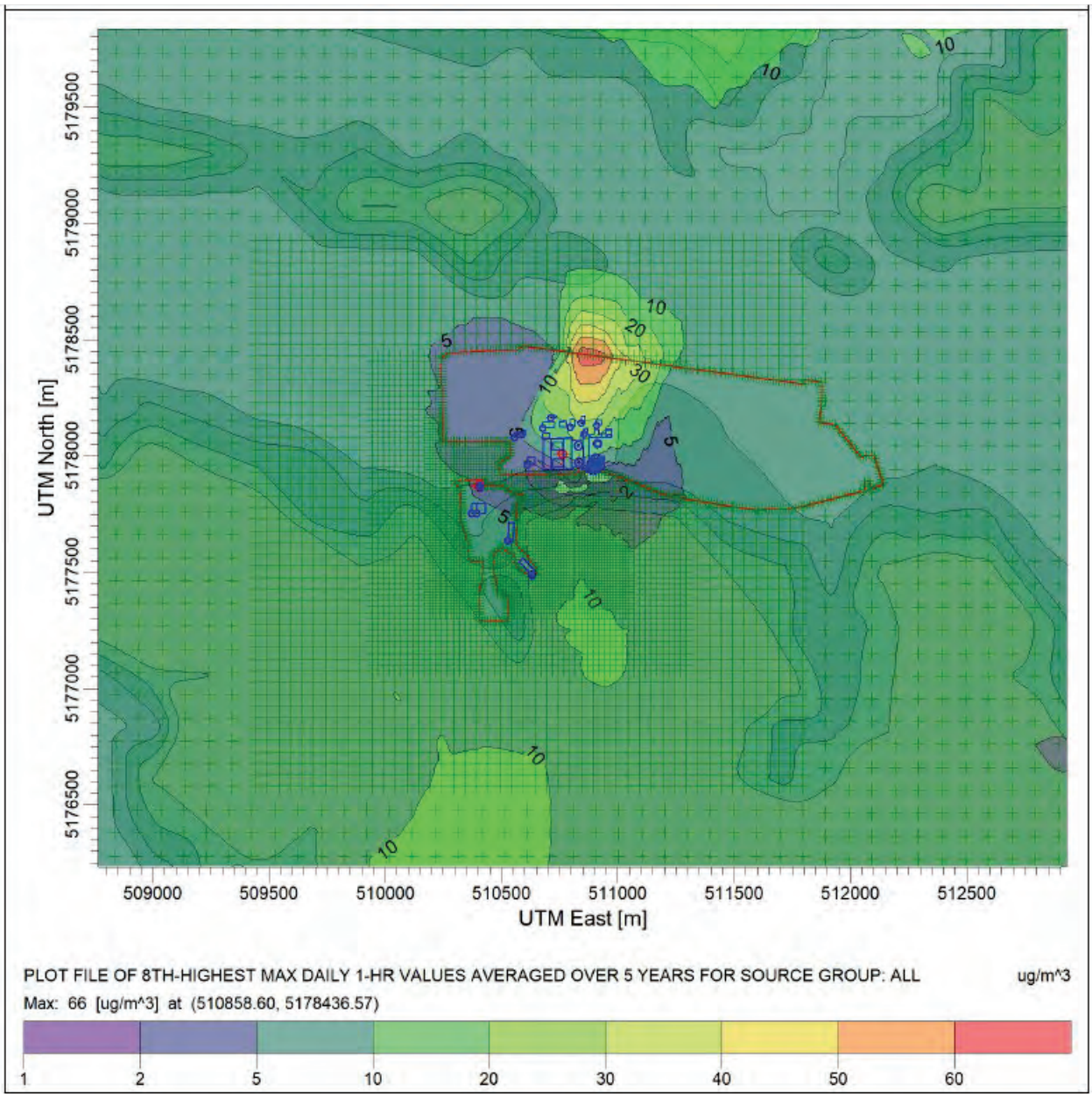


Figure B-1. AERMOD Predicted 1-hour NO_2 Concentration Contours

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

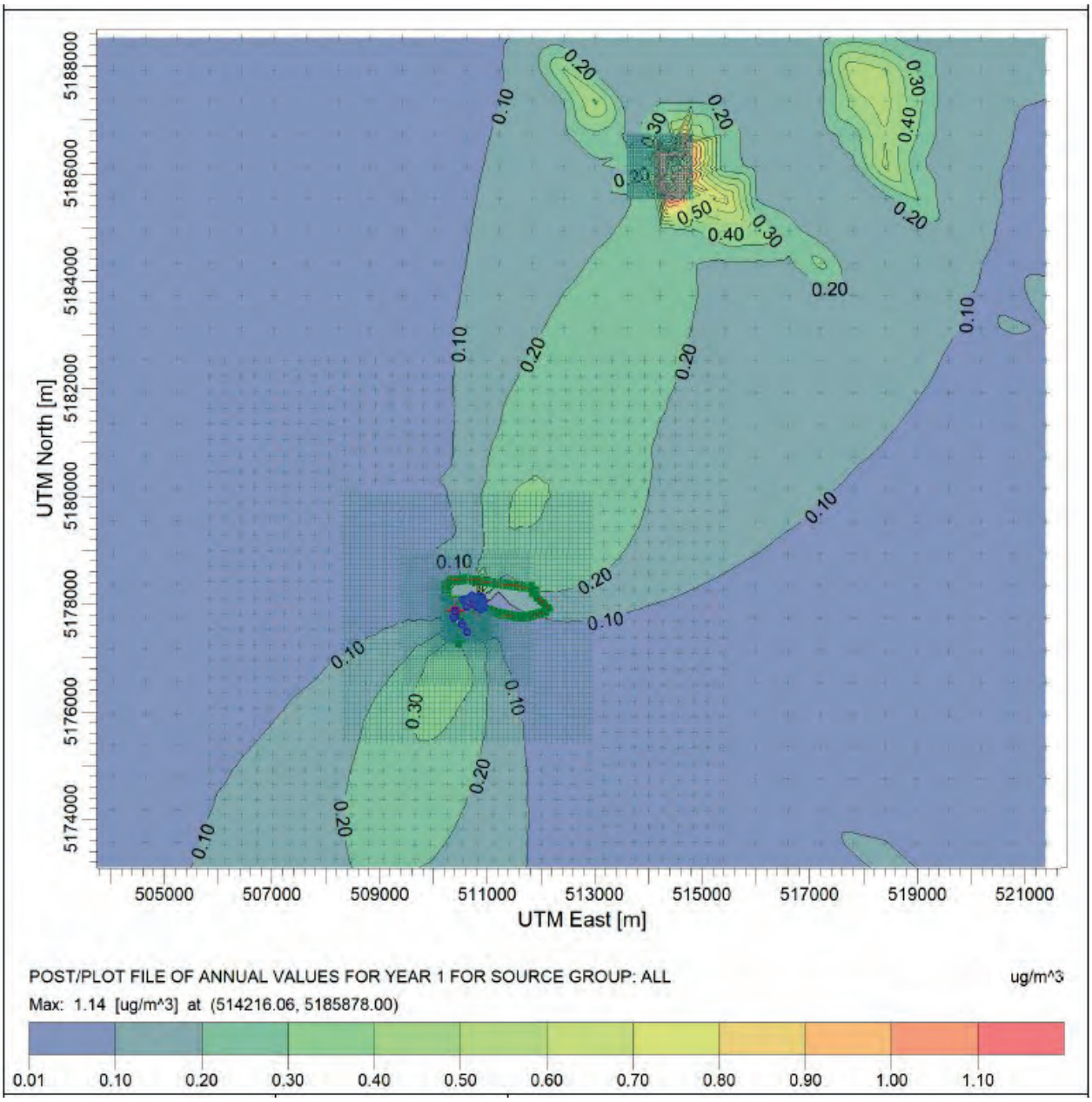


Figure B-2. AERMOD Predicted Annual (2020) NO_2 Concentration Contours

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

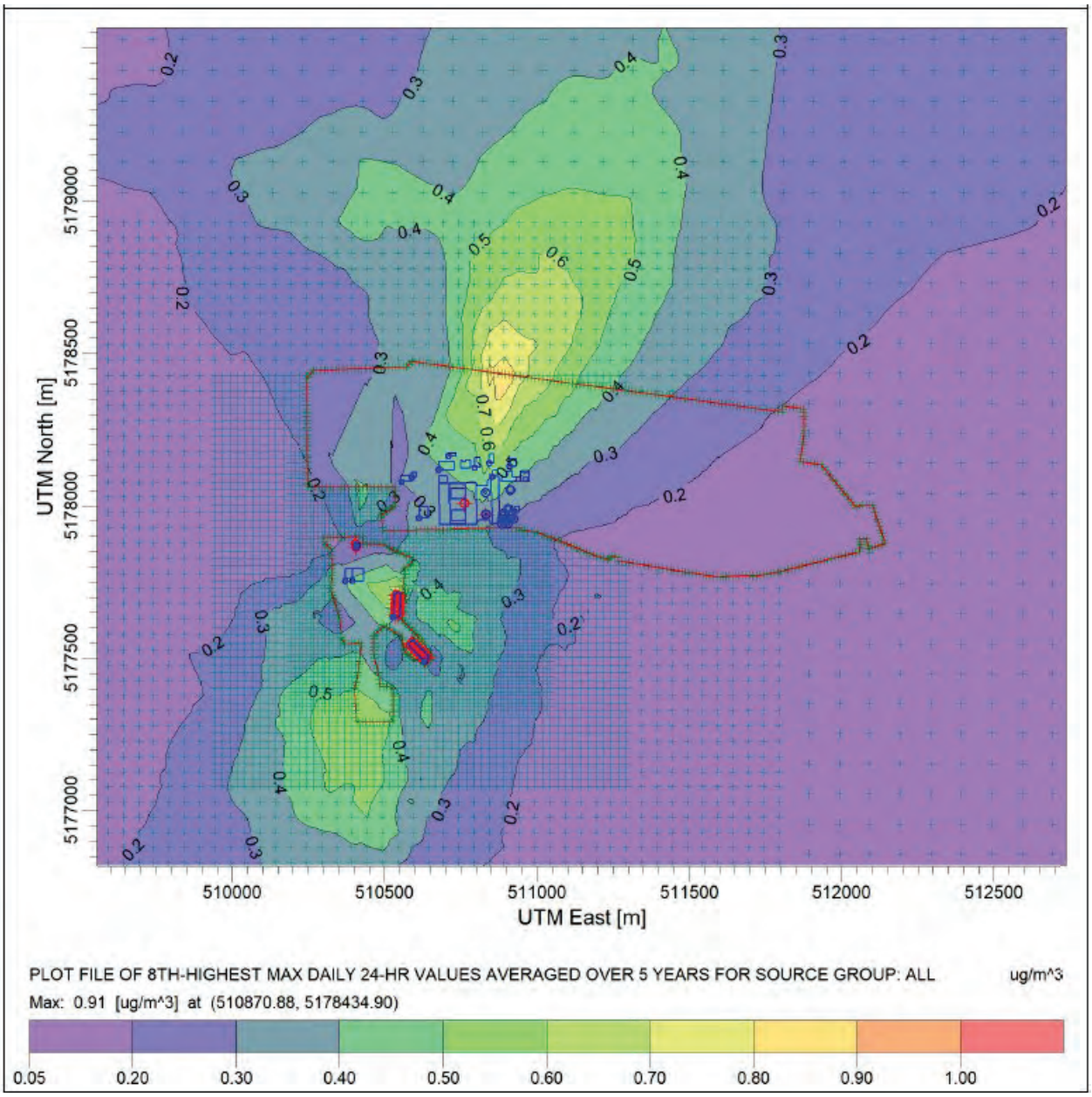


Figure B-3. AERMOD Predicted 24-Hour $PM_{2.5}$ Concentration Contours

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

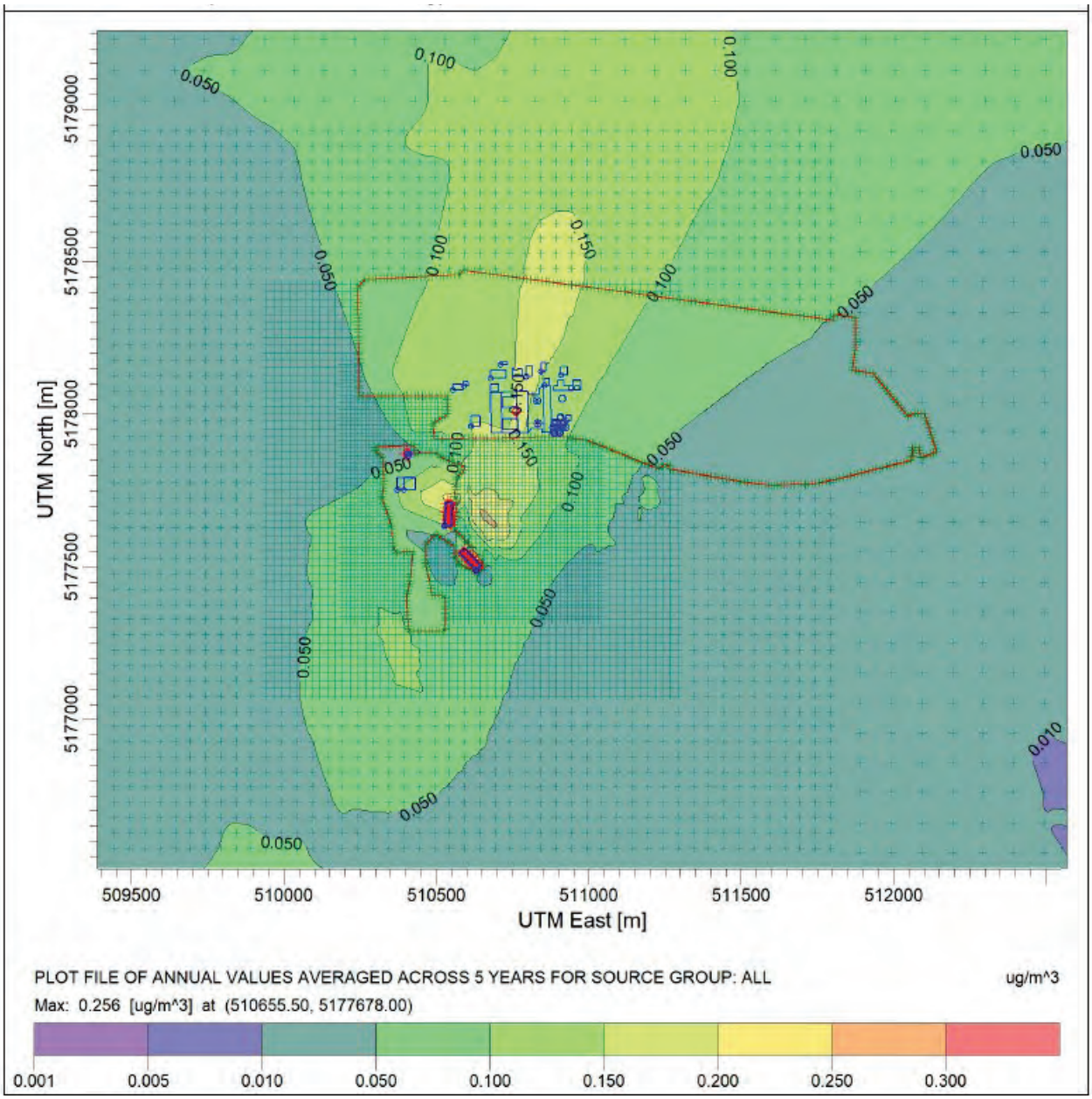


Figure B-4. AERMOD Predicted Annual $PM_{2.5}$ Concentration Contours

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX F: VISIBILITY MODELING ANALYSIS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

CALPUFF Class I Visibility Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

TransAlta Centralia Generation Station

Centralia, Washington

December 2025

Prepared for

TransAlta
913 Big Hanaford Road
Centralia, Washington 98531

For Submittal to

Southwest Clean Air Agency
5101 NE 82nd Ave.
Vancouver, Washington 98662
and
Washington Dept. of Ecology
300 Desmond Drive SE
Lacey, Washington 98503

Prepared by

TETRA TECH
10 Post Office Square, 11th Floor
Boston, MA 02109

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TABLE OF CONTENTS

1.0 INTRODUCTION 1

2.0 FACILITY DESCRIPTION 4

2.1 Site Location 4

2.2 Project Description 5

2.3 Summary of Annual Potential Emissions 5

3.0 CLASS I VISIBILITY IMPACT ASSESSMENT METHODOLOGY 7

3.1 Model Selection 7

3.2 Meteorological Data for CALPUFF 8

3.3 Model Domain 8

3.4 Source Data and Operating Scenarios 9

3.5 Class I Area Receptors 13

3.6 CALPUFF Model Options and Switch Settings 20

4.0 CLASS I VISIBILITY IMPACT ASSESSMENT RESULTS 22

5.0 REFERENCES 25

List of Tables

Table 2-1. Class I Areas within 300 km of the TransAlta Centralia Generation Station 5

Table 2-2. Project Annual Potential Emissions (tons per year, tpy) 6

Table 3-1. CALPUFF Domain LCC Projection Parameterizations 8

Table 3-2. Project BACT Summary 10

Table 3-3. Physical Stack Characteristics 11

Table 3-4. Stack Exhaust Parameters and Maximum Emission Rates used in the CALPUFF Modeling 12

Table 3-5. Number of Receptors at Each Class I Areas within 300 km of the TransAlta Centralia Generation Station 13

Table 3-6. CALPUFF Input Parameters for Deposition 20

Table 4-1. Natural Gas Conversion Project Visibility Improvement from 2010 BART Determination for the TransAlta Centralia Generation Station 23

Table 4-2. Predicted Number of Days with greater than 5% Change in Light Extinction at each Class I Area within 300 km of the TransAlta Centralia Generation Station 24

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

List of Figures

Figure 1-1. Facility Location Map 3
Figure 2-1. Project location with Class I Areas (white) within 300-km radius (circle) 4
Figure 3-1. CALPUFF Modeling Domain (LCC Projection) 9
Figure 3-2. Mount Rainier National Park Receptors Proposed for CALPUFF Modeling 14
Figure 3-3. Olympic National Park Receptors Proposed for CALPUFF Modeling 14
Figure 3-4. Goat Rocks Wilderness Area Receptors Proposed for CALPUFF Modeling 15
Figure 3-5. Mount Adams Wilderness Area Receptors Proposed for CALPUFF Modeling 15
Figure 3-6. Alpine Lakes Wilderness Area Receptors Proposed for CALPUFF Modeling 16
Figure 3-7. Mount Hood Wilderness Area Receptors Proposed for CALPUFF Modeling 16
Figure 3-8. Glacier Peak Wilderness Area Receptors Proposed for CALPUFF Modeling 17
Figure 3-9. Mount Jefferson Wilderness Area Receptors Proposed for CALPUFF Modeling 17
Figure 3-10. North Cascades National Park Receptors Proposed for CALPUFF Modeling 18
Figure 3-11. Pasayten Wilderness Area Receptors Proposed for CALPUFF Modeling 18
Figure 3-12. Mount Washington Wilderness Area Receptors Proposed for CALPUFF Modeling 19
Figure 3-13. Three Sisters Wilderness Area Receptors Proposed for CALPUFF Modeling 19

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Acronyms/Abbreviations

AMoN	Ammonia Monitoring Network
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BART	Clean Air Act Best Available Retrofit Technology
CALMET	The Meteorological Processing Model of the CALPUFF Modeling System
CALPOST	The Postprocessing Program of the CALPUFF Modeling System
CALPUFF	The CALPUFF Dispersion and Deposition Model
CTG	USGS composite theme grid land use files
dv	deciview
ddv	Delta-deciview
Ecology	Washington State Department of Ecology
FLAG	Federal Land Manager's Air Quality Related Values Work Group
FLM	Federal Land Manager
GHGs	greenhouse gases
HNO_3	nitric acid
H_2SO_4	sulfuric acid
IMPROVE	Interagency Monitoring of Protected Visual Environments
IWAQM	Interagency Workgroup on Air Quality Modeling
km	kilometer
LCC	Lambert Conformal Conic projection
m	meters
MMIF	EPA Mesoscale Model Interface Program
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NH_3	ammonia
NO_3^-	nitrates
NO_X	nitrogen oxides
NPS	National Park Service
O_3	ozone
PMC	coarse particulate matter with a diameter greater than 2.5 microns

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
The Project	Conversion of coal to natural gas firing in Unit 2 project
PSD	Prevention of Significant Deterioration
QA/QC	quality assurance/quality control
SO_2	sulfur dioxide
SO_4^{2-}	sulfate
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WRF	Weather Research Forecast Model

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility (Facility), which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application that requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. This facility is a recognized regional haze source and has Clean Air Act Best Available Retrofit Technology (BART) requirements in place. The BART program was instituted by Congress to reduce regional haze and restore visibility in national parks and wilderness areas (mandatory federal Class I areas). A CALPUFF visibility analysis was required for this Project because “any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled” (as described in the Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant, (Ecology, July 2020)). Detailed visibility modeling procedures were presented in the *CALPUFF Class I Visibility Modeling Protocol* submitted to the Southwest Clean Air Agency (SWCAA), Washington Department of Ecology (Ecology), and the Federal Land Managers (FLM) at the National Park Service (NPS), National Forest Service (NFS) and United States Fish and Wildlife Service (USFWS) on October 22, 2025. This document is the Class I visibility modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project’s location and expected emissions. Section 3 presents a detailed description of the modeling approach proposed for evaluating visibility impacts of the proposed Project including: source data, model selection, modeling domain, meteorological data, Class I Area receptors, CALPUFF model options, monthly ambient monitored ozone and ammonia background concentrations, as well as postprocessing for visibility impacts. Section 4 presents the visibility results at all Class I areas within 300 km of the Project. References cited in the document are presented in Section 5. To facilitate the review of this Report, the individual familiar with the CALPUFF

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

Modeling Consultant: Liz Hendrick, CCM
Tetra Tech, Inc.
10 Post Office Square, 11th Floor
Boston, MA 02109
Telephone: (978) 303-8524
Email: Liz.Hendrick@tetratech.com

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

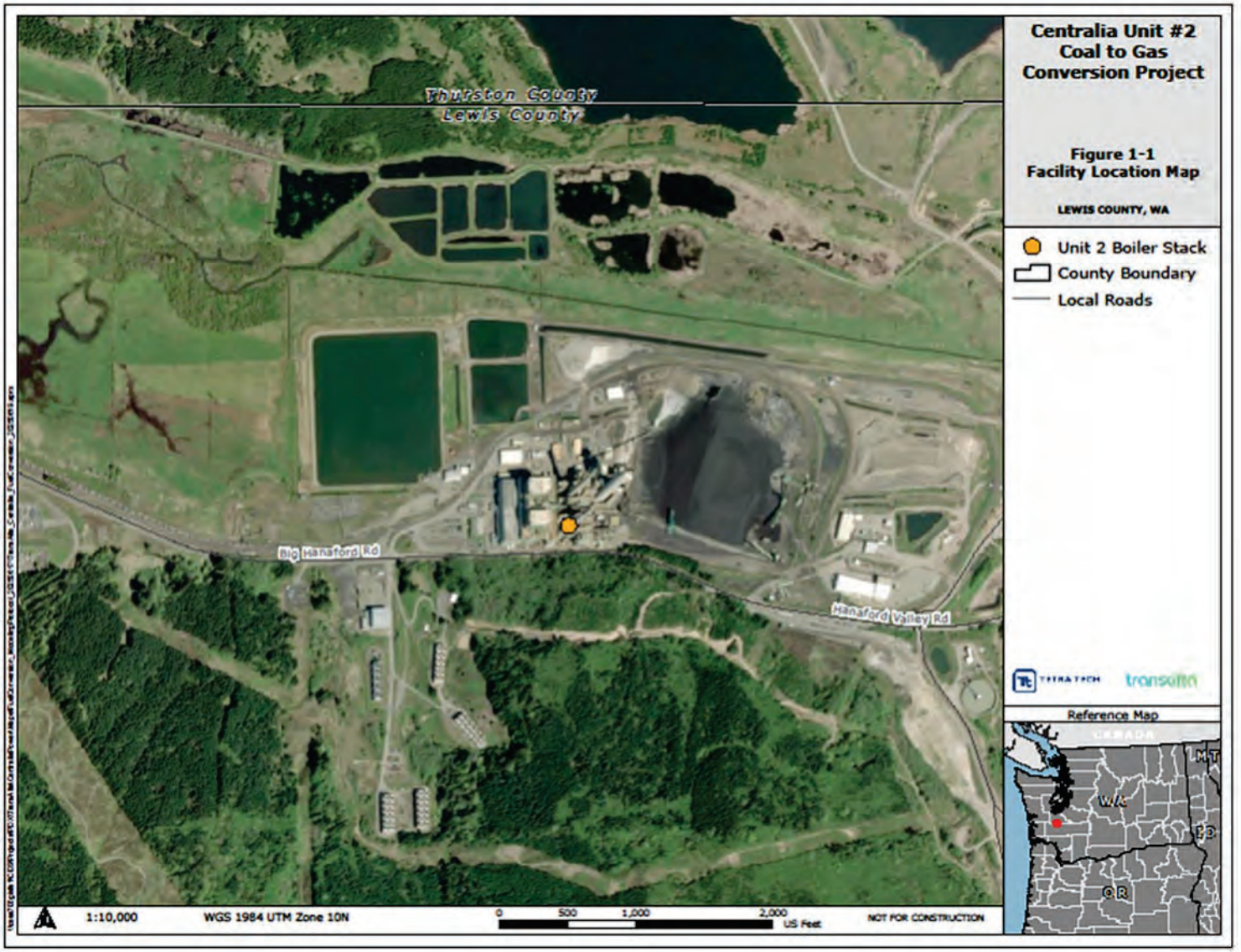


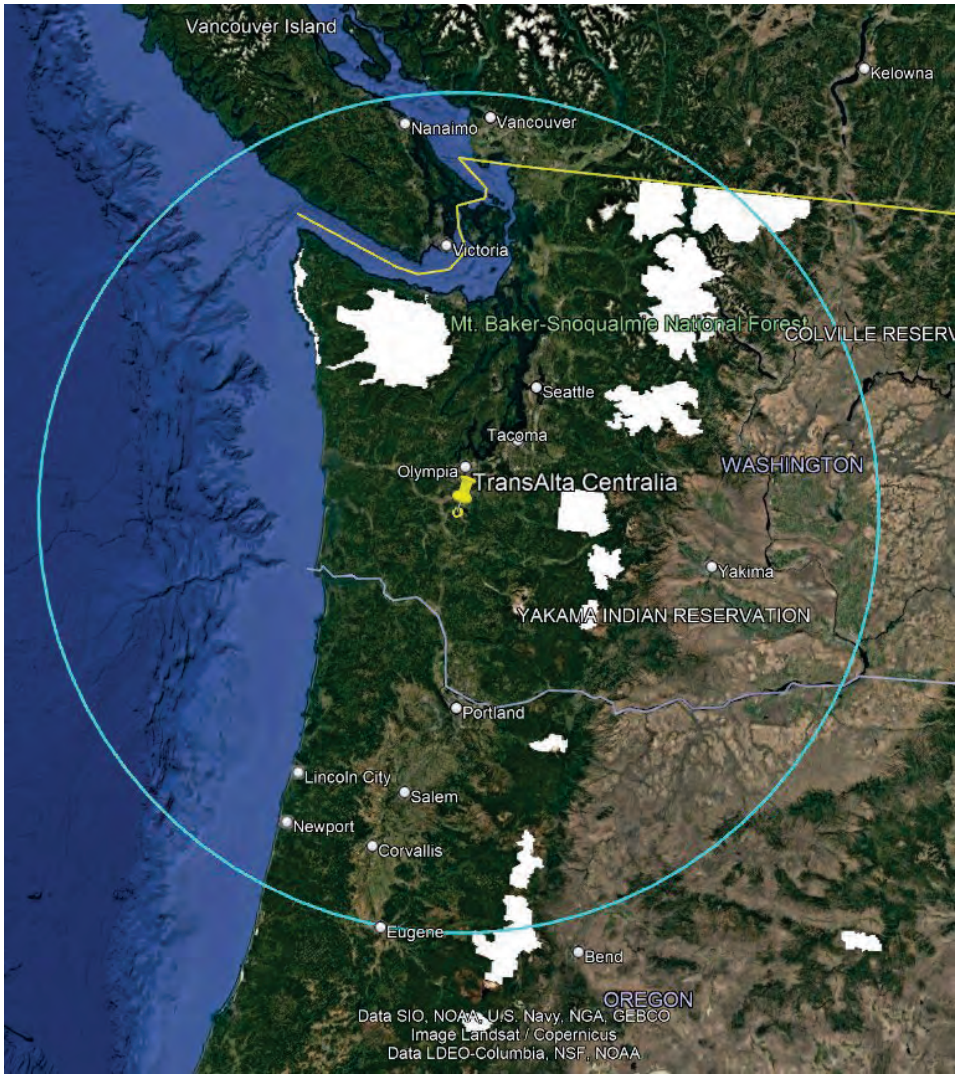
Figure 1-1. Facility Location Map

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

2.0 FACILITY DESCRIPTION

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land. Figure 2-1 presents an aerial graphic showing the TransAlta Plant location with a 300-kilometer (km) radius circle. The Class I areas are shown in white. There are 12 Class I areas within 300 km of the Project. Table 2-1 lists the Class I areas and closest distance from the Project Unit #2 stack to the nearest edge of the Class I area. A visibility analysis has been conducted for each Class I area.



Source: Google Earth

Figure 2-1. Project location with Class I Areas (white) within 300-km radius (circle)

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 2-1. Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Distance (km)
Mount Rainier National Park	71.7
Olympic National Park	90.3
Goat Rocks Wilderness Area	97.2
Mount Adams Wilderness Area	110.5
Alpine Lakes Wilderness Area	122.8
Mount Hood Wilderness Area	170.1
Glacier Peak Wilderness Area	185.0
Mount Jefferson Wilderness Area	230.2
North Cascades National Park	231.2
Pasayten Wilderness Area	260.9
Mount Washington Wilderness Area	273.7
Three Sisters Wilderness Area	286.5

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The project is not designed nor intended to operate continuously or at a high capacity or baseload factor. While additional modeling is needed, current expectations are that the facility will operate for less than 40% of hours on an annual basis over the life of the project; at a capacity factor of approximately 20% as the majority of operating hours are expected to be at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project includes the replacement of the existing diesel-fired auxiliary boiler with a new natural gas-fired auxiliary boiler, two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The facility's primary fuel will be natural gas, which will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boiler via a short 1300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-2. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied, as necessary. Potential emission rates for Unit #2 are based upon natural gas combustion at full load

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

operation for 5,168 hours per year (i.e., 59% capacity factor). Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year. Note: the pollutants in Table 2-2 are listed for completeness; not all are visibility-impacting pollutants.

Table 2-2. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[b,c]	Water Bath Heaters (2) [b,d]	Cooling Towers (2)	Project Wide Totals
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.0 CLASS I VISIBILITY IMPACT ASSESSMENT METHODOLOGY

3.1 Model Selection

CALPUFF is a Lagrangian modeling system recommended for Class I area air quality impact assessments by the Federal Land Managers (FLM) Workgroup. From April 2003 until January 2017, CALPUFF was the USEPA's preferred model for assessing National Ambient Air Quality Standards (NAAQS) and/or Prevention of Significant Deterioration (PSD) increments in situations of long-range transport (at distances greater than 50 km [31 mi]) of emission sources. With the 2017 revisions to the Guideline on Air Quality Models (Appendix W to 40 CFR Part 51) (USEPA 2017), CALPUFF was delisted as a USEPA-preferred model, yet retained as a screening technique for long-range transport assessments for NAAQS and PSD increments. Nevertheless, the CALPUFF modeling system has remained the FLM's preferred model for assessing Air Quality Related Values (AQRV) at Class I areas and is used in this visibility assessment. AERMOD, a steady-state Gaussian model, is the USEPA's preferred model for regulatory applications within 50 km of a source and was used for this Project's NAAQS and toxics assessments. However, because the Class I areas are over 50 km away (Table 2-1) and AERMOD does not account for chemical transformations during long-range transport, it is unsuitable for the Class I visibility analysis. Therefore, CALPUFF is recommended for long-range visibility modeling. The current USEPA-approved version of CALPUFF, version 5.8.5, was used in this modeling analysis.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on the transport, transformation, dispersion, and removal of air pollutants. It treats emissions as a series of discrete puffs, each tracked individually until it exits the modeling domain. The model calculates each puff's contribution to receptor concentrations or deposition fluxes separately, allowing users to analyze individual source impacts or aggregate impacts over source groups.

CALPUFF utilizes three-dimensional meteorological fields generated by the CALMET model, which can be based on prognostic meteorological model outputs (e.g., the Weather Research and Forecasting model, WRF), station data (surface observations and upper air soundings), or a hybrid combination of both. CALPUFF can also accept prognostic meteorological data that is processed through the USEPA Mesoscale Model Interface Program (MMIF).

Designed for application over spatial scales ranging from tens to hundreds of kilometers, CALPUFF incorporates algorithms to address sub-grid scale effects such as terrain impingement, as well as longer-range processes including pollutant removal by wet scavenging and dry deposition, chemical transformations, and visibility impacts from particulate matter.

The model is especially well suited for complex flow situations involving spatially variable meteorological conditions influenced by factors like complex terrain or nearby water bodies. CALPUFF can simulate plume fumigation events (e.g., coastal fumigation or inversion breakup), low wind speed or calm conditions, and other scenarios where steady-state, straight-line models are inadequate. Additionally, it can assess the cumulative impact of multiple, spatially distributed sources with temporally varying emissions over large regions.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

CALPOST, the CALPUFF modeling system postprocessor, will be used to generate the visibility impacts from the CALPUFF runs of concentrations. The current USEPA-approved version is CALPOST version 6.221. CALPOST performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations.

CALPUFF View

CALPUFF View is a CALPUFF model graphical user interface (GUI) developed and maintained by Lakes Environmental (Ontario, Canada). The software amalgamates the various CALPUFF pre- and post-processing programs, providing a user-friendly model setup wizard interface and other tools to create a graphical display of the various model inputs and outputs for visualization and quality assurance/quality control (QA/QC). CALPUFF View has been specifically developed to facilitate long-range visibility and deposition assessments for Class I areas as described in the Federal Land Manager's Air Quality Related Values Work Group (FLAG) 2010, containing a database of the various parameters for each specific Class I area as defined in Tables 5 through 10 of FLAG 2010. The CALPUFF View software was used to facilitate the visibility modeling assessment.

3.2 Meteorological Data for CALPUFF

The USFWS provided three-dimensional gridded meteorological files for the 3-year period of 2018-2020 for use as input to CALPUFF. The USFWS prepared the files using the USEPA MMIF that converts prognostic meteorological model output fields to the parameters and formats required for direct input into CALPUFF. The CALPUFF meteorological grid has a 12 km horizontal resolution with ten vertical layers, defined as consistent with the default layers specified by USEPA/FLM guidance (cell face heights of 20, 40, 80, 160, 320, 640, 1200, 2000, 3000 and 4000 meters).

3.3 Model Domain

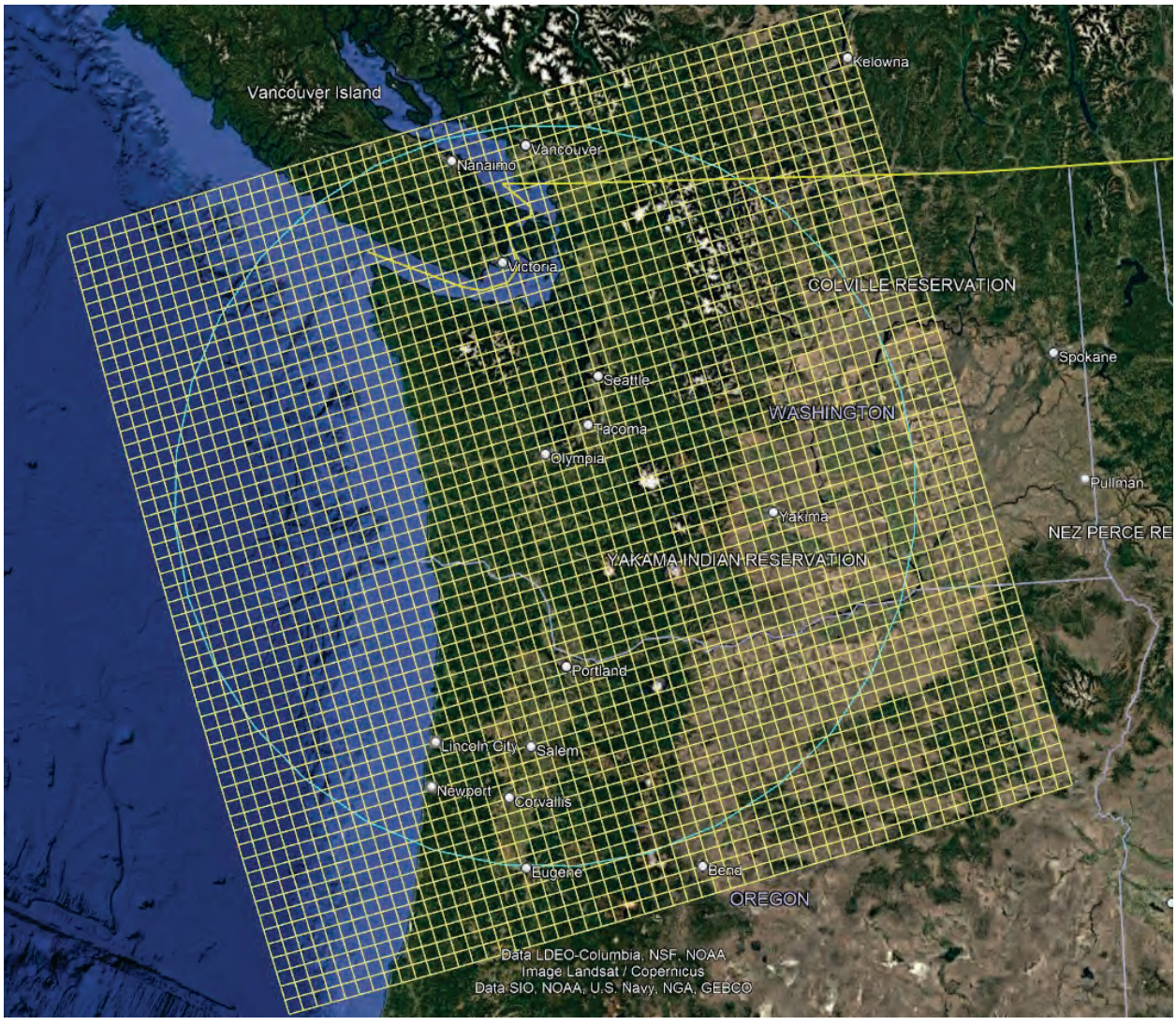
The modeling domain was defined by a 300 km radius with a buffer area beyond the radius (to allow for modeling of potential contaminant re-circulation), 660 km x 660 km, centered at Unit #2 at approximately 46.756°N, 122.858°W. The domain extends over the Pacific Ocean to the west, into Canada to the north and into Oregon to the south. Because the modeling domain covers such a large region, to account for the curvature of the earth, Lambert Conformal Conic (LCC) projection coordinates were used to define the meteorological grid points and source and receptor locations in CALPUFF. The parameterization of the CALPUFF domain is described in Table 3-1. The CALPUFF modeling domain is shown in Figure 3-1.

Table 3-1. CALPUFF Domain LCC Projection Parameterizations

CALPUFF Domain Parameter	Setting
XBTZ (Time Zone)	-8 (Pacific)
RLAT0 (degrees)	40.574°N
RLON0 (degrees)	97.000°W
XLAT (degrees)	33.000°N
XLAT2 (degrees)	45.000°N
NX	55
NY	55

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

CALPUFF Domain Parameter	Setting
NZ	10
DGRIDKM (km)	12
ZFACE (m)	0., 20, 40, 80, 160, 320, 640, 1,200, 2,000, 3,000, 4,000
XORIGKM (km)	-2268.0
YORIGKM (km)	618.0



Basemap: Google Earth

Figure 3-1. CALPUFF Modeling Domain (LCC Projection)

3.4 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year);

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) dew point (water bath) heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

As required by USEPA and Washington regulations, air permit applications for new major facilities must include a BACT review in accordance with 40 CFR 52.21(j) and WAC 173-400-830(1)(d) (for affected pollutants where the Project area is designated as an attainment area). Washington and Southwest Clean Air Agency (SWCAA) regulations also require a BACT review for minor new source review pollutants in accordance with WAC 173-400-030(13) and SWCAA 400-110. Table 3-2 lists the preliminarily proposed BACT control options for each source.

Table 3-2. Project BACT Summary

Source/Pollutant	Control Technology
Unit #2	
NO_X	Low NOx burners, combustion optimization system, flue gas recirculation
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel
Auxiliary Boiler	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)
Dew Point Heaters	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)

Table 3-3 summarizes the physical stack characteristics used in the modeling. Detailed emissions and source parameter data are provided in Table 3-4. The particulate matter is speciated into PMC (coarse particulate matter with a diameter greater than 2.5 microns) and $PM_{2.5}$ (particulate matter with a diameter equal to or less than 2.5 microns). For Class I visibility impairment modeling, the FLMs request that maximum 24-hour emission scenarios be evaluated. The Unit #2 boiler is modeled firing natural gas at full load (100%) assuming simultaneous operation of the auxiliary boiler, dew point heaters and cooling towers to determine total Project visibility impacts.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 3-3. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		LLC E (m)	LLC N (m)			
U2_100	Unit 2 Boiler (100% load)	-1950623.51	965448.66	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	-1950677.81	965513.85	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	-1951061.05	965475.59	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	-1951062.93	965466.73	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	-1951003.57	965214.12	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	-1950999.04	965226.47	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	-1950994.80	965239.08	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	-1950990.63	965250.83	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	-1950985.83	965264.70	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	-1950981.26	965277.22	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	-1950993.42	965209.71	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	-1950989.38	965222.20	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	-1950985.14	965234.82	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	-1950980.97	965246.56	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	-1950976.17	965260.44	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	-1950971.60	965272.95	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	-1950942.03	965051.80	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	-1950948.28	965063.42	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	-1950954.66	965075.60	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	-1950960.64	965087.92	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	-1950967.14	965100.10	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	-1950973.39	965111.69	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	-1950951.58	965046.56	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	-1950957.45	965058.54	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	-1950963.72	965070.32	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	-1950969.89	965082.56	93.96	19.91	7.62
COOLT2_K	Cooling Tower 2 Cell K	-1950976.30	965094.63	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	-1950982.53	965106.41	93.96	19.91	7.62

[a] Converted from UTM Zone 10, WGS-84 datum to Lambert Conformal Conic NWS-84 using the Lakes Environmental Coordinate Converter. Projection origin (Lat, Lon) = 40.574 deg N, 97.0 deg W with standard parallels of 33 deg N and 45 deg N.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 3-4. Stack Exhaust Parameters and Maximum Emission Rates used in the CALPUFF Modeling

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)				
			NO_x	PMC	$PM_{2.5}$	SO_2	SO_4
U2_100	441.48	29.77	103.948	0.0	6.488	0.679	0.010
AUXBLR	422.04	11.73	0.282	0.0	0.129	0.013	3.06-05
DPH_1	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
DPH_2	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
COOLT1_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_L	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_L	293.15	9.70	-	0.0015	0.0022	-	-

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

The CALPUFF modeling does not include building downwash, as the Class I areas are more than 50 km away from the sources. Downwash is the phenomena of disturbed atmospheric flow in the immediate vicinity of a structure that results in higher ground-level concentrations at a closer proximity to the source than would otherwise occur if the structures were not there. For long-range transport it is more conservative to allow the plume to travel undisturbed by local structures.

3.5 Class I Area Receptors

The National Park Service (NPS) provides receptors for use in Class I area modeling analyses. There are a total of 5,881 receptors in the Class I areas within 300 km of the source. Table 3-5 lists the number of receptors at each Class I area provided by the NPS and used in this modeling analysis.

Table 3-5. Number of Receptors at Each Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Number of Receptors
Mount Rainier National Park	405
Olympic National Park	714
Goat Rocks Wilderness Area	181
Mount Adams Wilderness Area	313
Alpine Lakes Wilderness Area	693
Mount Hood Wilderness Area	310
Glacier Peak Wilderness Area	444
Mount Jefferson Wilderness Area	183
North Cascades National Park	888
Pasayten Wilderness Area	931
Mount Washington Wilderness Area	359
Three Sisters Wilderness Area	460

The Class I receptor locations are provided by the NPS in latitude/longitude format. CALPUFF View allows for the direct download and import of Class I area receptors into the model and converts them to LCC format for use in CALPUFF consistent with the original WRF projection. The receptor elevations provided in the NPS receptor file were used in the CALPUFF modeling.

The receptors used in the modeling in each Class I area are shown in Figures 3-2 through 3-13 (figures courtesy of the NPS website). Some of the Class I areas straddle the 300 km radius circle with the nearest receptors within 300 km of TransAlta Centralia and some of the receptors beyond 300 km. The modeling domain is large enough so that the Class I area receptors were modeled (including those that are beyond 300 km from the source).

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

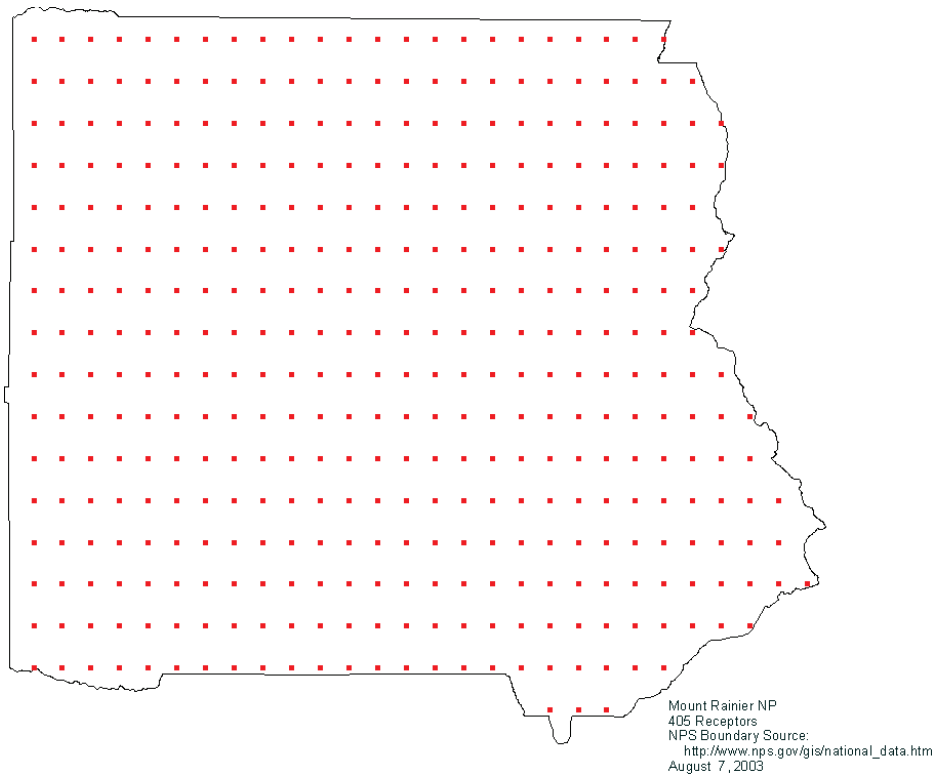


Figure 3-2. Mount Rainier National Park Receptors Proposed for CALPUFF Modeling

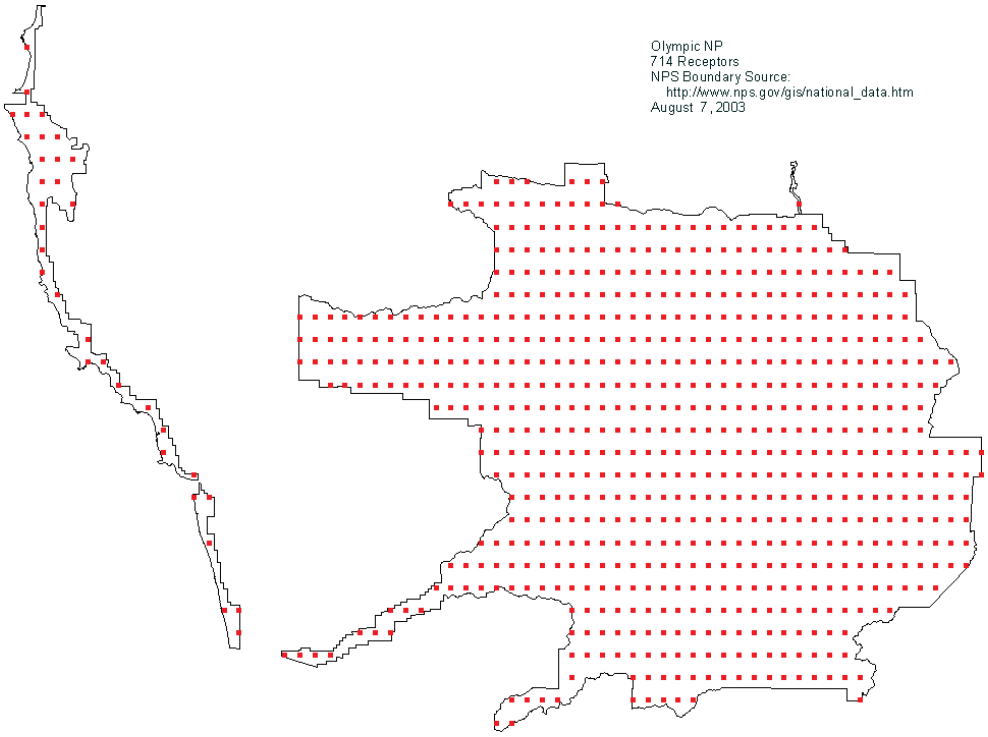


Figure 3-3. Olympic National Park Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

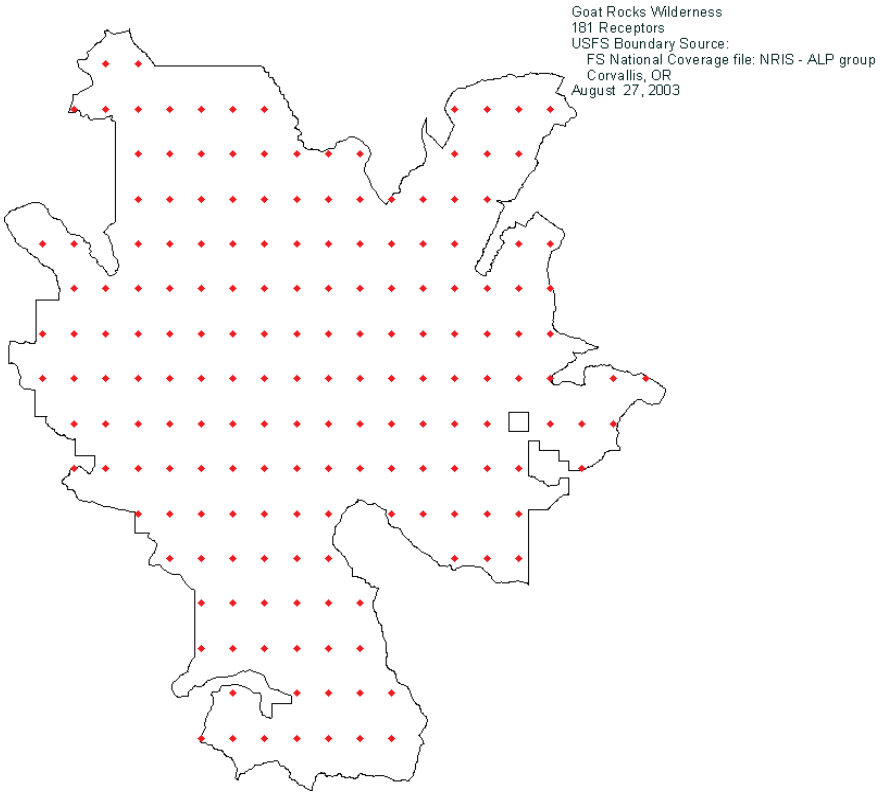


Figure 3-4. Goat Rocks Wilderness Area Receptors Proposed for CALPUFF Modeling

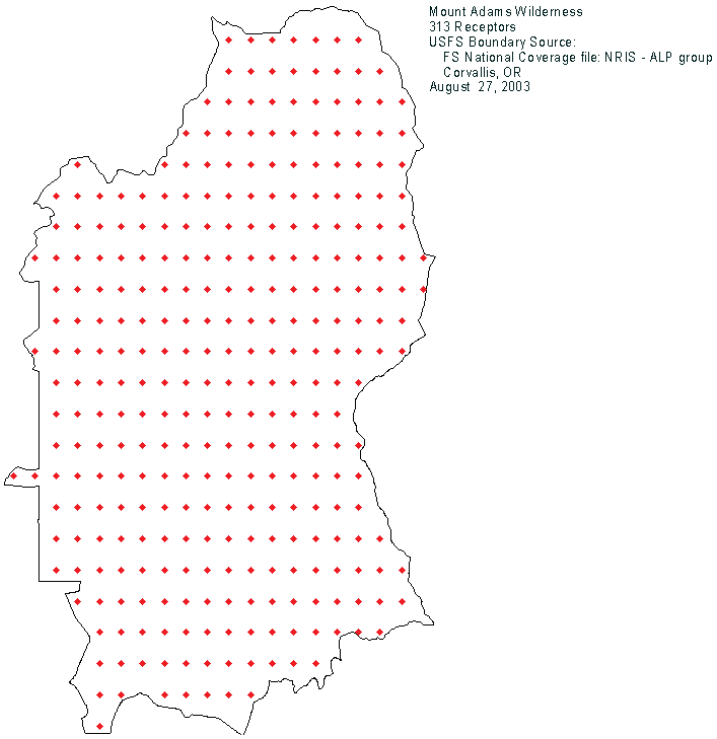


Figure 3-5. Mount Adams Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

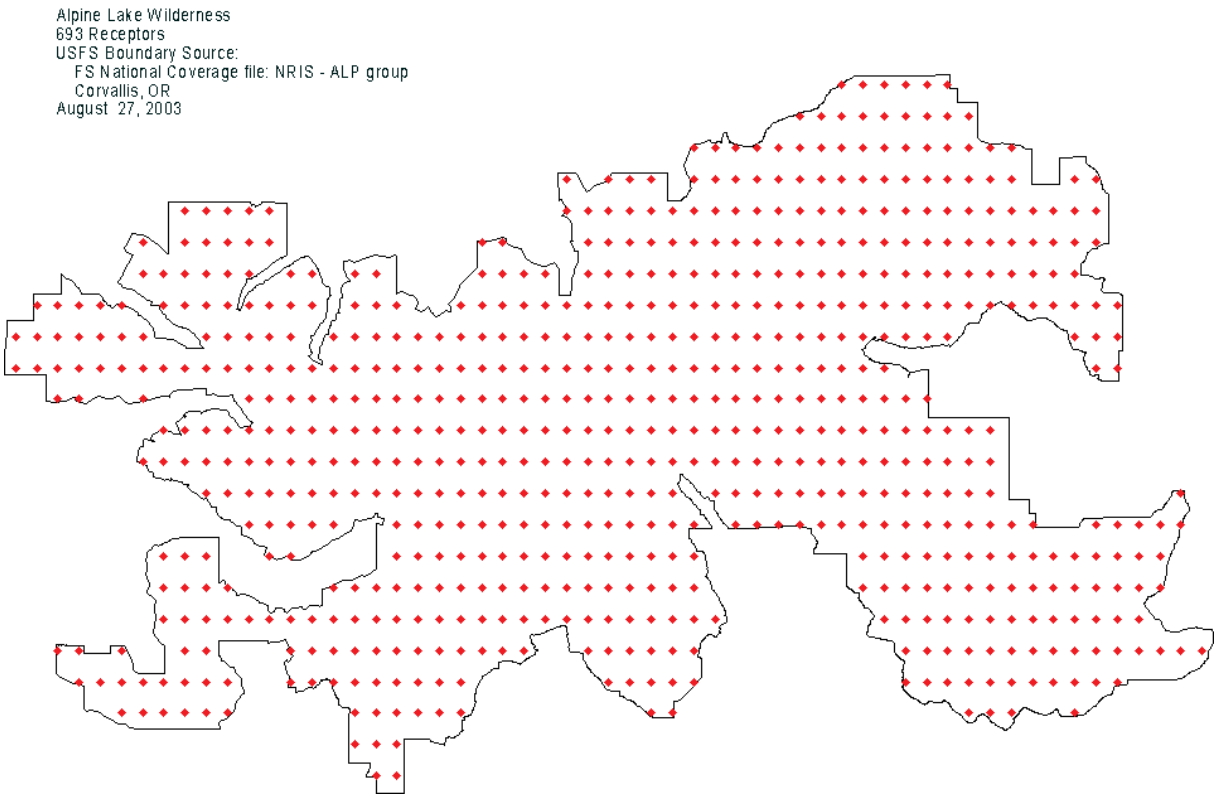


Figure 3-6. Alpine Lakes Wilderness Area Receptors Proposed for CALPUFF Modeling

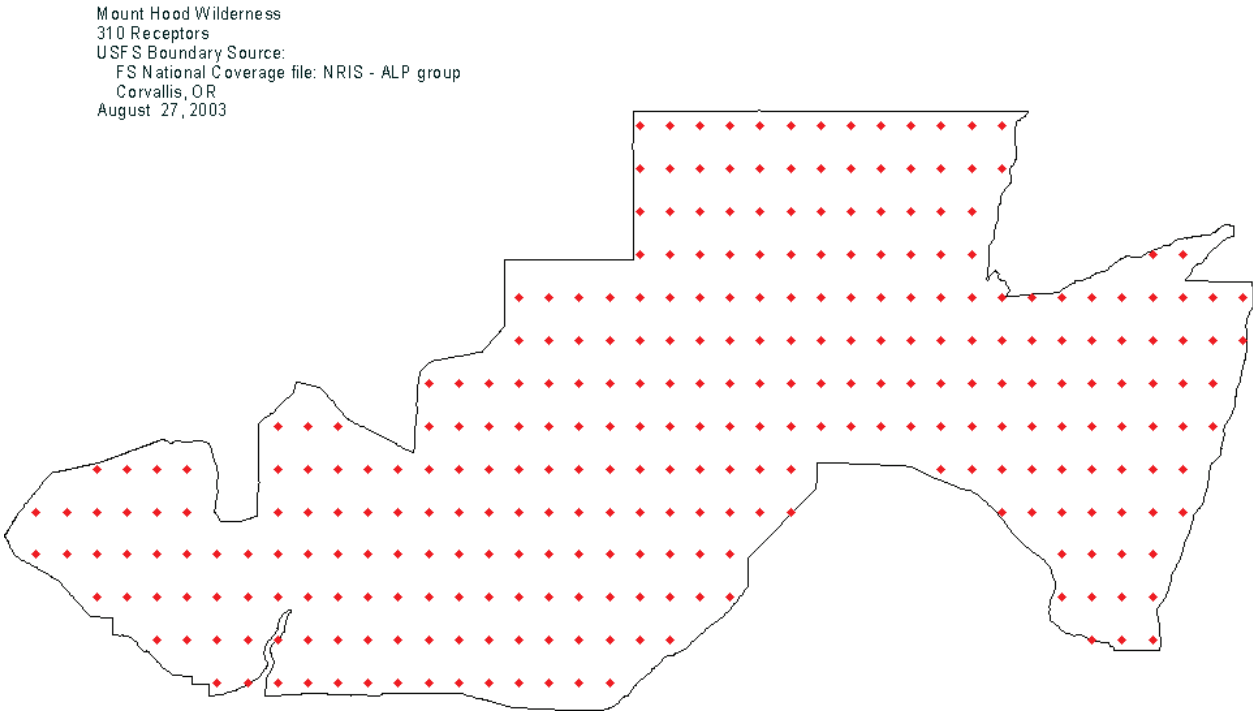


Figure 3-7. Mount Hood Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

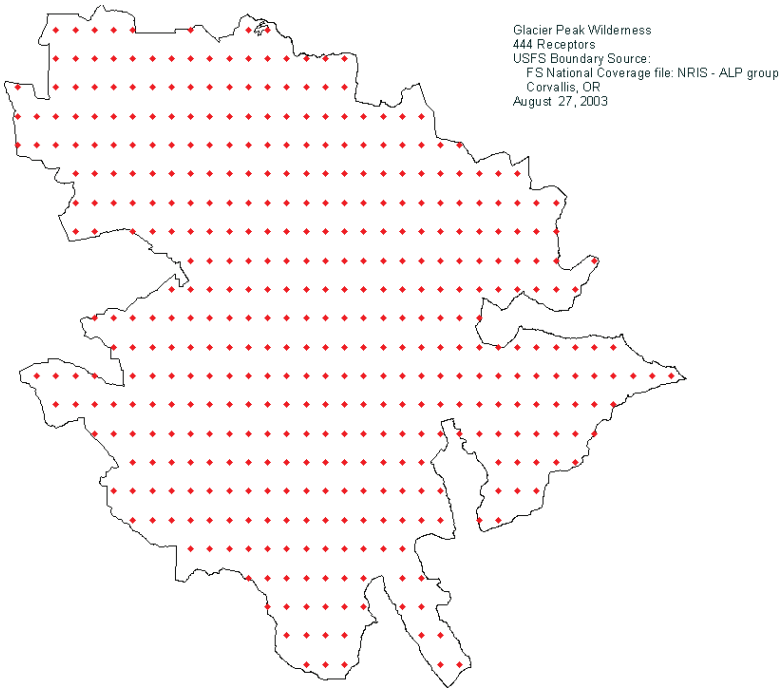


Figure 3-8. Glacier Peak Wilderness Area Receptors Proposed for CALPUFF Modeling

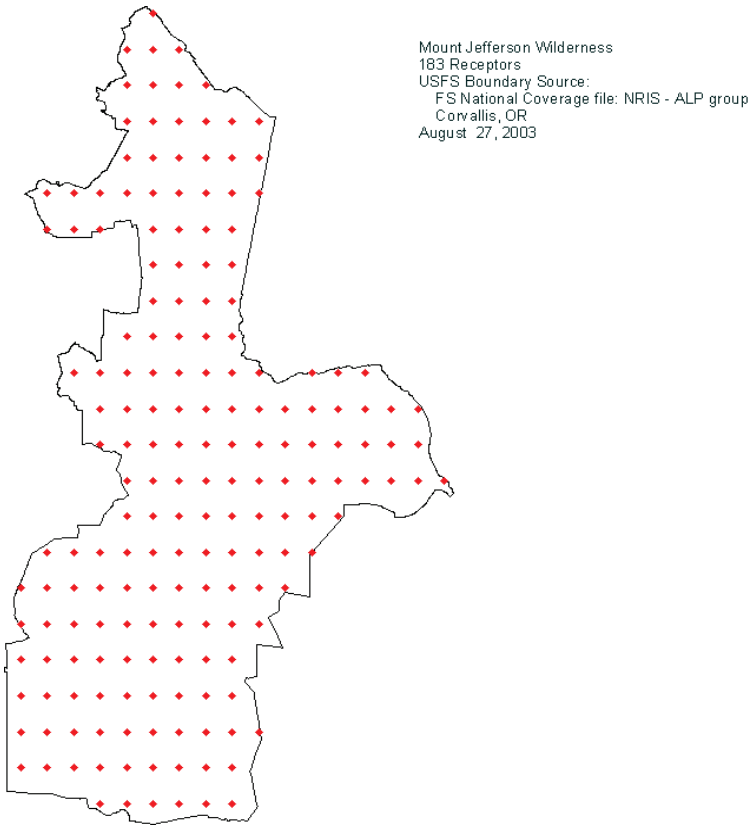


Figure 3-9. Mount Jefferson Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD



Figure 3-10. North Cascades National Park Receptors Proposed for CALPUFF Modeling

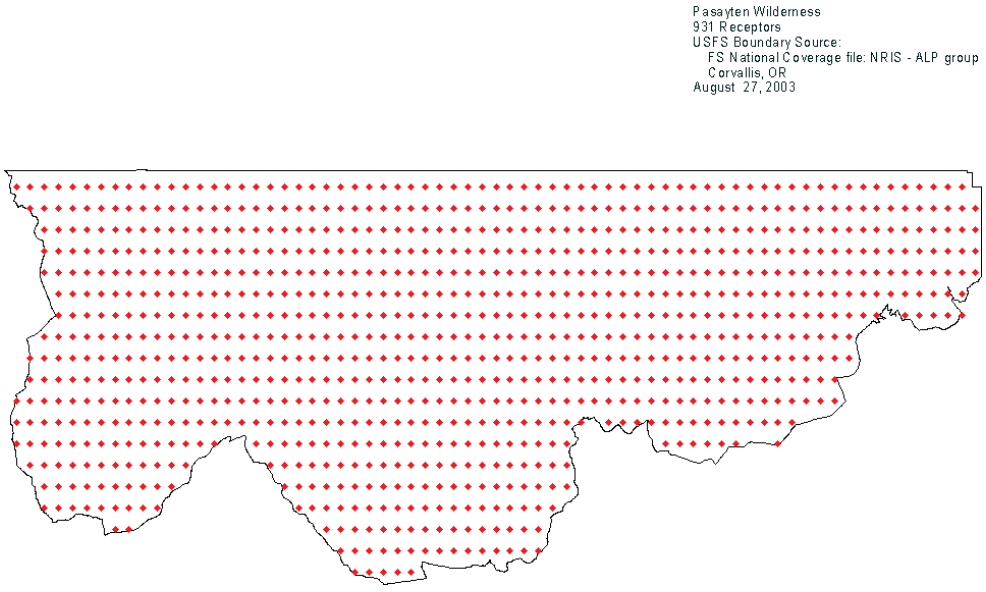


Figure 3-11. Pasayten Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

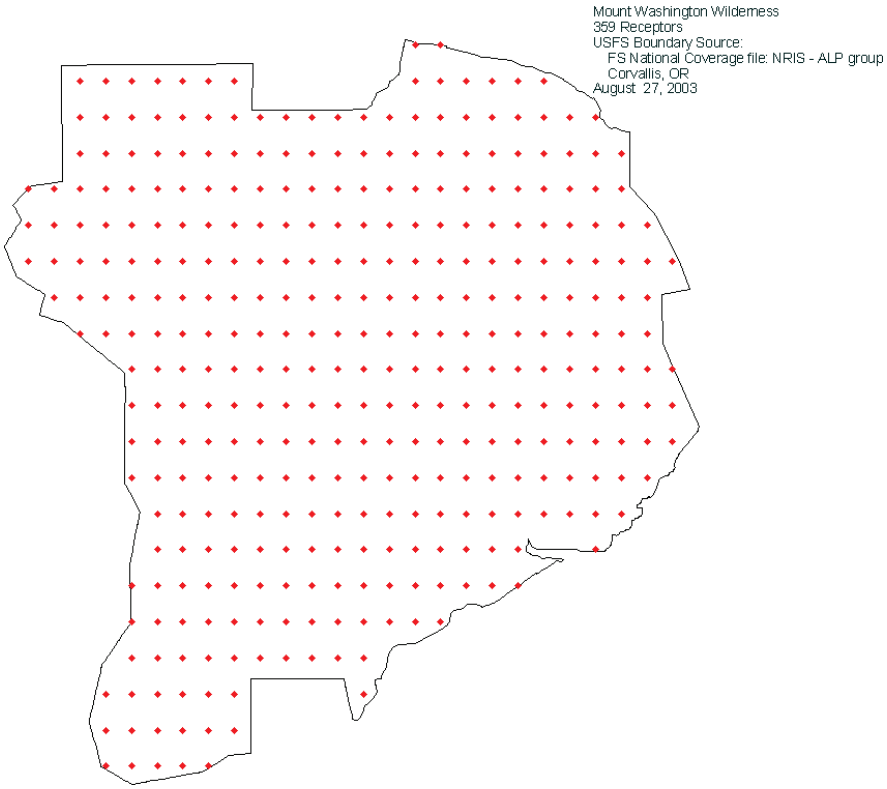


Figure 3-12. Mount Washington Wilderness Area Receptors Proposed for CALPUFF Modeling

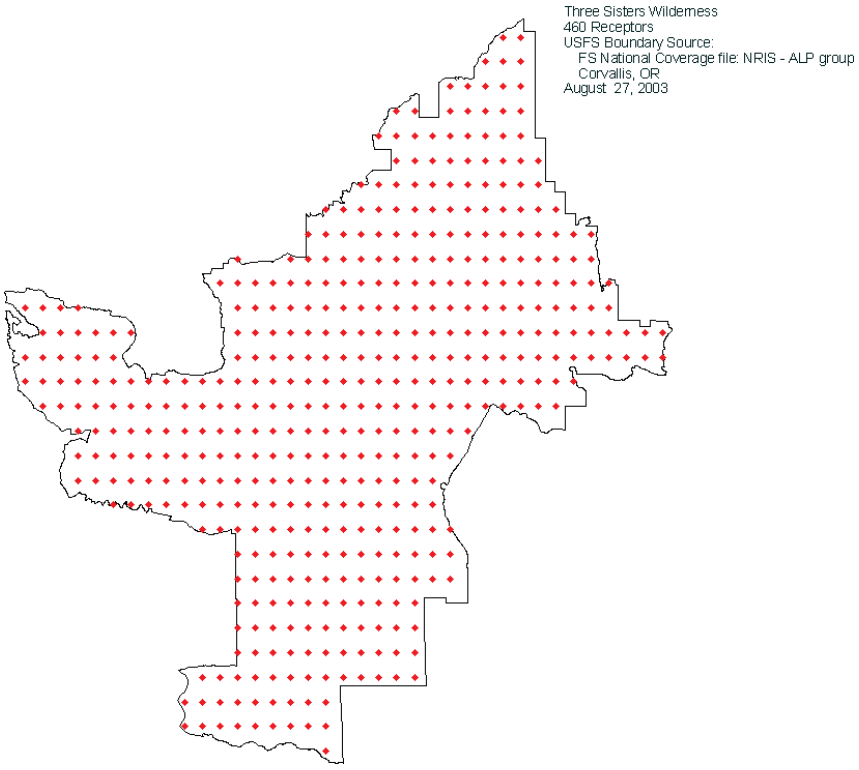


Figure 3-13. Three Sisters Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.6 CALPUFF Model Options and Switch Settings

The CALPUFF switch settings used in the modeling correspond to the regulatory options specified in Appendix B of the IWAQM Phase 2 document (EPA 1998).

Both dry and wet deposition were modeled using CALPUFF's default depositional parameters. Gaseous phase dry deposition was modeled for NOx, HNO_3, and SO_2, while particle deposition was assumed for NO_3-, SO_4^{2-} as well as particulate matter. H_2SO_4 emissions were treated as primary SO_4^{2-}. Default scavenging coefficients for the wet deposition algorithm provided in CALPUFF were used for SO_2, SO_4^{2-}, HNO_3, NH_3, NO_3^-, PMC and $PM_{2.5}$. The deposition parameters used in the modeling are presented in Table 3-6.

Table 3-6. CALPUFF Input Parameters for Deposition

Parameter	SO_2	NO_X	HNO_3	NH_3
Dry Deposition of Gases				
Diffusivity (cm^2/s)	0.1509	0.1656	0.1628	0.23
Alpha Star	1000	1	1	1
Reactivity	8	8	18	18
Mesophyll Resistance (s/cm)	0	5	0	0
Henry's Law Coefficient	0.04	3.5	8.0E-8	7.0E-7
	SO_4	NO_3-	PMC	$PM_{2.5}$
Dry Deposition of Particles				
Geometric Mass Mean Diameter (microns)	0.48	0.48	0.48	0.48
Geometric Standard Deviation (microns)	2.0	2.0	2.0	1.5
Other Dry Deposition Parameters				
Reference cuticle resistance (s/cm)		30		
Reference ground resistance (s/cm)		10		
Reference pollutant reactivity		8		
Number of particle-size intervals		9		
Vegetation state in unirrigated areas		Active and unstressed		

Pollutant	Scavenging Coefficient Liquid (1/sec)	Scavenging Coefficient Frozen (1/sec)
Precipitation Scavenging Coefficients		
SO_2	3.0×10^{-5}	0
SO_4	1.0×10^{-4}	3.0×10^{-5}
NO_X	0	0
HNO_3	6.0×10^{-5}	0
NH_3	7.9×10^{-5}	3.0×10^{-5}
NO_3-	1.0×10^{-4}	3.0×10^{-5}
$PM_{2.5}$	1.0×10^{-4}	3.0×10^{-5}
PMC	1.0×10^{-4}	3.0×10^{-5}

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Chemical transformations of NOx to nitrates (NO_3^-) and nitric acid (HNO_3), and SO_2 to sulfate (SO_4^{2-}) were evaluated using CALPUFF's MESOPUFF II chemistry scheme as recommended for long-range transport in IWAQM 1998. The rate of chemical transformations in the MESOPUFF II scheme is dependent on the concentration of ozone and ammonia in the ambient air. Representative ozone concentrations for May through September were defined on a monthly basis as the average of 8-hour observations at the Lacey-Olympia air quality monitor (Monitor ID #53-067-0013) located approximately 22.5 miles to the north-northeast of the source. This is the closest most representative monitor but only operates during the ozone season. For the remainder of the year (i.e., January through April and October through December) the data set was supplemented with observations from the Seattle monitor (Monitor ID #53-033-0080). The Seattle monitor is approximately 66 miles to the northeast of the source and operates year-round. The monitored ozone concentrations at the Lacey-Olympia and Seattle monitors are similar during the ozone season months; therefore, the Seattle monitor can serve as a suitable surrogate for the rest of the year. There is an ozone monitor on Mount Rainier, which is slightly closer to the source (~62 miles to the east) than the Seattle monitor, but it is situated at an elevation of 1615 meters. Both the Lacey-Olympia and the Seattle monitors are at base elevations (70 m and 105 m, respectively) much closer to the source base elevation (between 68-93m). Therefore, the Lacey-Olympia and Seattle ozone data are more representative of background concentrations near the source than the Mount Rainier data. The ozone concentrations from the most recently available three-year period (2022-2024) were used.

Washington state has only one ambient monitor measuring ammonia concentrations, which is part of the Ammonia Monitoring Network (AMoN). This monitor, AMoN-WA99, is in Mount Rainier National Park at an elevation of 424 meters, lower than the nearby ozone monitor. Monthly background ammonia concentrations were calculated using data collected from 2022 to 2024.

The CALPUFF modeling system postprocessor, CALPOST will be used to generate the visibility impacts from the CALPUFF runs. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest EPA/FLM recommendations. CALPOST will run separately for each Class I area for each year modeled. The CALPOST parameter MVISBK will be set to 8, sub-mode five (M8_MODE = 5), and the background hygroscopic and non-hygroscopic aerosol levels are derived from the annual average natural conditions for each Class I area as provided in Table 6 of the FLAG 2010 guidance. When calculating the sulfate and nitrate components of the visibility extinction coefficient, relative humidity adjustment factors are applied because these aerosols are hygroscopic, and the addition of water enhances their scattering efficiencies. The monthly relative humidity adjustment factors from Tables 7 through 9 in FLAG 2010 for each Class I area are input to the RHFAC array in CALPOST (which are auto-populated for each specific Class I area by the CALPUFF View software).

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

4.0 CLASS I VISIBILITY IMPACT ASSESSMENT RESULTS

Visibility is typically characterized by visual range (VR) - the greatest distance at which a large dark object can be seen - or by the light-extinction coefficient (b_{ext}), which measures light attenuation per unit distance due to scattering and absorption by atmospheric gases and particles (EPA 1998). A constant fractional change in b_{ext} produces a similar perceptual change in a scene regardless of baseline conditions. Based on this perceived visual change, an alternate visibility index called the deciview (dv) has been defined by the USEPA's Regional Haze Rule (USEPA, 1999). This unitless index is a logarithmic scale based on the light extinction coefficient (b_{ext}), specifically designed to correlate with human perception. It ensures that uniform changes in haziness correspond to consistent incremental changes in perceived visibility across the full range of conditions, from pristine to highly impaired. The deciview scale increases as visibility worsens. The delta deciview (ddv) is the difference between total visibility and natural visibility, quantifying the impairment caused by human-generated pollution.

The visibility impairment threshold of concern for Class I areas is not exceeded if the 98th percentile change in light extinction is less than 5% for each modeled year when compared to the annual average natural condition value. The 98th percentile test applies to the number of days that any modeled receptor in a Class I area exceeds the 5% degradation threshold. If the analysis indicates the 98th percentile value of change in light extinction is equal to or greater than 5% for any year (i.e., 5% change exceeded on 8 or more days per year), then FLAG 2010 guidance indicates the results may be further scrutinized to determine the frequency of the exceedances and the conditions under which the exceedances are predicted.

CALPOST, the CALPUFF modeling system postprocessor, was used to generate visibility impacts from the CALPUFF output. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations. For the assessment of a 24-hour average regional haze visibility impact, light extinction was determined as a function of the modeled concentrations of primary (H_2SO_4) and secondary sulfate (SO_4^{2-}), secondary nitrate (NO_3^-), nitrogen dioxide (NO_2, assumed as 100% of NO_X emissions) and fine and coarse particulate matter ($PM_{2.5}$ and PMC, respectively) based on maximum allowable 24-hour mass emission rates.

The CALPUFF visibility analysis was conducted for this Project because any request to repower one or both units at the Centralia plant requires modeling the impact of repowering on visibility, as stated in the Technical Support Document for the Second BART Order Revision – TransAlta Centralia Generation Plant (July 2020). When the plant operated two coal-fired units, TransAlta prepared visibility impairment modeling following the Oregon/Idaho/Washington/USEPA Region 10 BART modeling protocol. Ecology prepared a BART Determination Support Document in 2009, revised in 2010 (Ecology, 2010). Ecology determined that BART controls for NOx and SO_2 would "result in a visibility improvement from the baseline impacts at Mount Rainier National Park of approximately 1.13 dv, with improvements of 0.67 to 1.45 dv at other affected Class I areas" (Ecology, 2010).

The conversion from two coal-fired units to a single natural gas unit will further reduce emissions and enhance visibility in these Class I areas. Table 4-1 summarizes the expected visibility improvements based on the Project's predicted CALPUFF modeling results compared to the 2010 BART

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

determination. In 2010, four control scenarios were evaluated against the baseline operation; Table 4-1 presents the control scenario with the lowest deciview change (ddv) from the Ecology 2010 BART Determination, representing the cleanest outcome. The improvement of visibility is shown as a range in Table 4-1 because the 2010 document reported only the maximum of three years of modeling, while the current analysis includes results for all three years modeled.

All twelve Class I areas within 300 km of the Project will experience significant visibility improvements. The largest improvement is predicted at Mount Rainier National Park, with a 2.459 ddv reduction, and the smallest at Pasayten Wilderness Area, with a 0.619 ddv reduction.

Table 4-1. Natural Gas Conversion Project Visibility Improvement from 2010 BART Determination for the TransAlta Centralia Generation Station

Class I Area	Natural Gas Conversion Project Largest Predicted Delta Deciview (ddv)			2010 BART [a] Single year Lowest Control Scenario (ddv)	Range of Visibility Improvement (reduction in ddv)
	2018	2019	2020		
Mount Rainier National Park	1.069	1.302	0.900	3.359	2.057 – 2.459
Olympic National Park	1.148	1.075	0.322	2.506	1.358 – 2.184
Goat Rocks Wilderness Area	1.035	0.674	0.835	3.069	2.034 – 2.395
Mount Adams Wilderness Area	0.695	0.575	0.695	1.984	1.289 – 1.409
Alpine Lakes Wilderness Area	0.602	0.904	0.679	2.949	2.045 – 2.347
Mount Hood Wilderness Area	0.243	0.661	0.233	1.978	1.317 – 1.745
Glacier Peak Wilderness Area	0.297	0.320	0.216	2.036	1.716 – 1.820
Mount Jefferson Wilderness Area	0.148	0.148	0.163	1.150	0.987 – 1.002
North Cascades National Park	0.209	0.263	0.239	1.570	1.307 – 1.361
Pasayten Wilderness Area	0.456	0.196	0.211	1.075	0.619 – 0.879
Mount Washington Wilderness Area	0.130	0.136	0.115	1.106	0.970 – 0.991
Three Sisters Wilderness Area	0.126	0.150	0.158	1.139	0.981 – 1.013

[a] Data obtained from Table 3-1 in the 2010 BART Determination (Ecology, 2010)

Table 4-2 presents the results of light extinction calculations for each of the twelve Class I areas within 300 km of the Project. It shows the predicted maximum change in light extinction and the number of days per year with a predicted change exceeding 5%. Note that the 98th percentile threshold for a change in light extinction of 5% or more is considered exceeded if it occurs on 8 or more days per year. For ten of the twelve Class I areas modeled, predicted changes in light extinction do not exceed the 98th percentile threshold in any modeled year. At the closest Class I area, Mount Rainier National Park, the predicted change exceeds the threshold by 2 days for both 2018 and 2020 meteorological conditions, and by 8 days in 2019. At the Goat Rocks Wilderness Area, the threshold is exceeded by 2 days in 2018 but not exceeded in 2019 or 2020.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Table 4-2. Predicted Number of Days with greater than 5% Change in Light Extinction at each Class I Area within 300 km of the TransAlta Centralia Generation Station

Class I Area	Approx. Distance and Direction from Project	Number of Days >5% Change in Light Extinction		
		2018	2019	2020
Mount Rainier National Park	71.7 km to E	9	15	9
Olympic National Park	90.3 km to NNW	3	2	0
Goat Rocks Wilderness Area	97.2 km to ESE	9	3	7
Mount Adams Wilderness Area	110.5 km to SE	3	1	2
Alpine Lakes Wilderness Area	122.8 km to NE	1	2	5
Mount Hood Wilderness Area	170.1 km to SSE	0	1	0
Glacier Peak Wilderness Area	185.0 km to NNE	0	0	0
Mount Jefferson Wilderness Area	230.2 km to SSE	0	0	0
North Cascades National Park	231.2 km to NNE	0	0	0
Pasayten Wilderness Area	260.9 km to NNE	0	0	0
Mount Washington Wilderness Area	273.7 km to SSE	0	0	0
Three Sisters Wilderness Area	286.5 km to SSE	0	0	0

Note: Bold font indicates the 98th percentile value (i.e., 8 days or more per year) is exceeded.

Although Table 4-2 shows four exceedances of the visibility impairment threshold, these results should be interpreted in the context of the modeling assumptions. The CALPUFF model assumes continuous plant operation - 24 hours a day, every day of the year at full load. In reality, the plant will not be a baseload facility, and it is being permitted to operate up to an annual capacity factor of 59%, or approximately 215 days per year with varying levels of operation, the majority of which are expected to be at half-load or minimum stable generation levels (see Section 2.2). Therefore, the frequency of visibility impairment on the 98th percentile worst days must be considered alongside the likelihood that meteorological conditions causing higher visibility impacts will coincide with the days the plant is operational.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

5.0 REFERENCES

Earth Tech, Inc., 2000. A *User's Guide for the CALPUFF Dispersion Model (Version 5)*. Concord, Massachusetts 01742. January 2000.

Ecology, 2010. BART Determination Support Document for TransAlta Centralia Generation, LLC Power Plant, Centralia, Washington. Washington Department of Ecology – Air Quality Program, August 2009, revised April 2010.

Ecology, 2020. Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant. Washington Department of Ecology – Air Quality Program, July 2020.

NPS (National Park Service). 2010. Federal Land Manager's Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010), U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service. Natural Resources Report NPS/NRPC/NRR-2010/232, October.

USEPA, 1998. Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. EPA-454/R-98-019 (November 2024). Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711. December 1998.

USEPA, 1999. Regional Haze Regulations. Federal Register Vol. 64, No. 126, Thursday, July 1, 1999, Rules and Regulations.

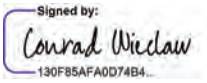
USEPA, 2017. Revisions to the Guideline on Air Quality Models; Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter. Codified in the Appendix W to 40 CFR Part 51. Federal Register Vol. 82, No. 10, January 17, 2017, Rules and Regulations.

Certificate Of Completion

Envelope Id: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD
Status: Completed
Subject: Complete with Docusign: TA_CTG_PSD Application_12_23_2025_compiled.pdf
Source Envelope:
Document Pages: 153
Signatures: 1
Envelope Originator:
Certificate Pages: 5
Initials: 0
Marina Tufts
AutoNav: Enabled
1100 - 1st Street SE
EnvelopeId Stamping: Enabled
Calgary, AB T2G 1B1
Time Zone: (UTC-07:00) Mountain Time (US & Canada)
marina_tufts@transalta.com
IP Address: 63.228.223.150

Record Tracking

Status: Original
12/23/2025 1:56:21 PM
Holder: Marina Tufts
marina_tufts@transalta.com
Location: DocuSign

Signer Events	Signature	Timestamp
Conrad Wieclaw conrad_wieclaw@transalta.com Engineering and Environmental Manager Security Level: Email, Account Authentication (None)	 Signature Adoption: Pre-selected Style Using IP Address: 63.228.223.150	Sent: 12/23/2025 2:09:41 PM Viewed: 12/23/2025 2:19:35 PM Signed: 12/23/2025 2:20:27 PM

Electronic Record and Signature Disclosure:
Accepted: 12/23/2025 2:19:35 PM
ID: 06435ca3-2ce1-4f48-adab-ec12ac6efacb

In Person Signer Events	Signature	Timestamp

Editor Delivery Events	Status	Timestamp

Agent Delivery Events	Status	Timestamp

Intermediary Delivery Events	Status	Timestamp

Certified Delivery Events	Status	Timestamp

Carbon Copy Events	Status	Timestamp
Vincent Light vincent_light@transalta.com Security Level: Email, Account Authentication (None)	COPIED	Sent: 12/23/2025 2:20:30 PM Viewed: 12/23/2025 2:28:11 PM
Andrea Ortega andrea_ortega@transalta.com Senior Environmental Planner Security Level: Email, Account Authentication (None)	COPIED	Sent: 12/23/2025 2:20:30 PM

Electronic Record and Signature Disclosure:
Accepted: 7/24/2025 2:57:41 PM
ID: 0c96112a-1f2b-404b-bd30-29659763776f

Electronic Record and Signature Disclosure:
Accepted: 10/28/2025 6:49:46 PM
ID: 10e6f9ab-a7e1-4caf-aa0c-a87c715e4b3e

Carbon Copy Events	Status	Timestamp
Scott Jeffers scott_jeffers@transalta.com Vice President TransAlta Corporation Security Level: Email, Account Authentication (None) **Electronic Record and Signature Disclosure:** Accepted: 5/1/2020 1:04:06 PM ID: bcc54ad2-7bc1-4b54-8f11-9b723d8798c5	COPIED	Sent: 12/23/2025 2:20:31 PM

Witness Events	Signature	Timestamp

Notary Events	Signature	Timestamp

Envelope Summary Events	Status	Timestamps
Envelope Sent	Hashed/Encrypted	12/23/2025 2:09:41 PM
Certified Delivered	Security Checked	12/23/2025 2:19:35 PM
Signing Complete	Security Checked	12/23/2025 2:20:27 PM
Completed	Security Checked	12/23/2025 2:20:31 PM

Payment Events	Status	Timestamps

Electronic Record and Signature Disclosure

ELECTRONIC RECORD AND SIGNATURE DISCLOSURE

From time to time, TransAlta Corporation (we, us or Company) may be required by law to provide to you certain written notices or disclosures. Described below are the terms and conditions for providing to you such notices and disclosures electronically through the DocuSign system. Please read the information below carefully and thoroughly, and if you can access this information electronically to your satisfaction and agree to this Electronic Record and Signature Disclosure (ERSD), please confirm your agreement by selecting the check-box next to 'I agree to use electronic records and signatures' before clicking 'CONTINUE' within the DocuSign system.

Getting paper copies

At any time, you may request from us a paper copy of any record provided or made available electronically to you by us. You will have the ability to download and print documents we send to you through the DocuSign system during and immediately after the signing session and, if you elect to create a DocuSign account, you may access the documents for a limited period of time (usually 30 days) after such documents are first sent to you. After such time, if you wish for us to send you paper copies of any such documents from our office to you, you will be charged a $0.00 per-page fee. You may request delivery of such paper copies from us by following the procedure described below.

Withdrawing your consent

If you decide to receive notices and disclosures from us electronically, you may at any time change your mind and tell us that thereafter you want to receive required notices and disclosures only in paper format. How you must inform us of your decision to receive future notices and disclosure in paper format and withdraw your consent to receive notices and disclosures electronically is described below.

Consequences of changing your mind

If you elect to receive required notices and disclosures only in paper format, it will slow the speed at which we can complete certain steps in transactions with you and delivering services to you because we will need first to send the required notices or disclosures to you in paper format, and then wait until we receive back from you your acknowledgment of your receipt of such paper notices or disclosures. Further, you will no longer be able to use the DocuSign system to receive required notices and consents electronically from us or to sign electronically documents from us.

All notices and disclosures will be sent to you electronically

Unless you tell us otherwise in accordance with the procedures described herein, we will provide electronically to you through the DocuSign system all required notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you during the course of our relationship with you. To reduce the chance of you inadvertently not receiving any notice or disclosure, we prefer to provide all of the required notices and disclosures to you by the same method and to the same address that you have given us. Thus, you can receive all the disclosures and notices electronically or in paper format through the paper mail delivery system. If you do not agree with this process, please let us know as described below. Please also see the paragraph immediately above that describes the consequences of your electing not to receive delivery of the notices and disclosures electronically from us.

How to contact TransAlta Corporation:

You may contact us to let us know of your changes as to how we may contact you electronically, to request paper copies of certain information from us, and to withdraw your prior consent to receive notices and disclosures electronically as follows:
To contact us by email send messages to: HR_Services@transalta.com

To advise TransAlta Corporation of your new email address

To let us know of a change in your email address where we should send notices and disclosures electronically to you, you must send an email message to us at HR_Services@transalta.com and in the body of such request you must state: your previous email address, your new email address. We do not require any other information from you to change your email address.

If you created a DocuSign account, you may update it with your new email address through your account preferences.

To request paper copies from TransAlta Corporation

To request delivery from us of paper copies of the notices and disclosures previously provided by us to you electronically, you must send us an email to HR_Services@transalta.com and in the body of such request you must state your email address, full name, mailing address, and telephone number. We will bill you for any fees at that time, if any.

To withdraw your consent with TransAlta Corporation

To inform us that you no longer wish to receive future notices and disclosures in electronic format you may:

i. decline to sign a document from within your signing session, and on the subsequent page, select the check-box indicating you wish to withdraw your consent, or you may;

ii. send us an email to HR_Services@transalta.com and in the body of such request you must state your email, full name, mailing address, and telephone number. We do not need any other information from you to withdraw consent.. The consequences of your withdrawing consent for online documents will be that transactions may take a longer time to process..

Required hardware and software

The minimum system requirements for using the DocuSign system may change over time. The current system requirements are found here: https://support.docusign.com/guides/signer-guide-signing-system-requirements.

Acknowledging your access and consent to receive and sign documents electronically

To confirm to us that you can access this information electronically, which will be similar to other electronic notices and disclosures that we will provide to you, please confirm that you have read this ERSD, and (i) that you are able to print on paper or electronically save this ERSD for your future reference and access; or (ii) that you are able to email this ERSD to an email address where you will be able to print on paper or save it for your future reference and access. Further, if you consent to receiving notices and disclosures exclusively in electronic format as described herein, then select the check-box next to 'I agree to use electronic records and signatures' before clicking 'CONTINUE' within the DocuSign system.

By selecting the check-box next to 'I agree to use electronic records and signatures', you confirm that:

- You can access and read this Electronic Record and Signature Disclosure; and
- You can print on paper this Electronic Record and Signature Disclosure, or save or send this Electronic Record and Disclosure to a location where you can print it, for future reference and access; and
- Until or unless you notify TransAlta Corporation as described above, you consent to receive exclusively through electronic means all notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you by TransAlta Corporation during the course of your relationship with TransAlta Corporation.

EXHIBIT 105-2

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600, Olympia, WA 98504-7600 • 360-407-6000

January 23, 2026

Conrad Wieclaw
TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

Re: TransAlta Centralia Generation, LLC – Incompleteness Letter for the TransAlta Centralia Plant Project

Dear Conrad Wieclaw:

On December 24, 2025, the Washington Department of Ecology (Ecology) received a Prevention of Significant Deterioration (PSD) application from TransAlta for the coal-to-natural-gas conversion project. Ecology processed the application base fee on December 24, 2025.

To complete our review, please address the following item:

- You have proposed good combustion practices as VOC BACT for Boiler #2, the auxiliary boiler, and the water bath heaters. Part of the proposal is to conduct boiler/heater tune-ups as required by the Boiler MACT and use of natural gas as the only fuel, both of which are work practice standards. While the use of natural gas reduces particulate matter and sulfur dioxide emissions compared to coal or diesel firing, it does not have the same effect for reducing VOC emissions. Therefore, we do not consider using natural gas as part of the VOC BACT determination.

  BACT is generally an emission limitation that reflects the maximum degree of emission reduction, considering effectiveness and energy, environmental, and economic impacts. Other non-numerical requirements may be used when measuring emissions is technically infeasible.

  You have identified VOC limits in the RBLC Clearinghouse ranging from 0.0016 to 0.0054 lb/MMBtu for units comparable to Boiler #2, and you have estimated a VOC emission rate of 0.003 lb/MMBtu. Based on this information, we conclude that VOC BACT for Boiler #2 should include a numerical emission limit. Please propose a VOC emission limit for Boiler #2 and provide supporting justification.

For the auxiliary boilers and water bath heaters, where information on similar-sized units is limited, a work practice standard alone may be acceptable. However, it would be helpful to identify specific combustion optimization measures, including instrumentation and control operating ranges and set points, to reflect good combustion practices.

Once the application is deemed complete, Ecology reserves the right to request additional information as needed to continue processing this application. If you have any questions, please contact me at 360-995-3448 or mengchiu.lim@ecy.wa.gov.

Sincerely,

MengChiu Lim, P.E.
Engineering & Permitting Section
Air Quality Program

cc: EPA Region 10
Richard Graw, USFS
Kirsten King, NPS
Clint Lamoreaux, SWCAA
Debbie Skibicki, Tetra Tech, Inc.

EXHIBIT 105-3

TransAlta Centralia
Generation LLC
913 Big Hanaford Road
Centralia, Washington
USA 98531

T: +1 (360) 736-9901
www.transalta.com

Conrad Wieclaw
Sr Manager, Engineering & Environment
Direct Line: (360) 807-8093
Email: conrad_wieclaw@transalta.com

March 10, 2026

Washington Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA
98531

Attention: MengChiu Lim, P.E., Engineering and Permitting Section

Dear Mr. Lim:

Re: Incompleteness Letter Response for the TransAlta Centralia Plant Project

TransAlta Centralia Generation LLC (TransAlta) is providing this response to the incompleteness letter dated January 23, 2026, from the Washington Department of Ecology (Ecology) regarding the TransAlta Centralia Plant Project. Within the discussion on Best Available Control Technology (BACT) for Volatile Organic Compounds (VOC), Ecology requested that TransAlta address two primary topics: (1) proposal of a VOC emission limit for Unit #2, and (2) the identification of specific work practices for the auxiliary boiler and water bath heaters to reflect good combustion practices for VOC control.

VOC Numeric Limit for Unit #2

TransAlta has consulted engineering firms and vendors with utility boiler expertise on this matter, including one with natural gas conversion experience. They have stated that a typical VOC emissions guarantee for natural gas boilers (including conversions) is 0.003 lb/MMBtu. TransAlta's confidence in that emissions rate is demonstrated in the formal Request for Proposal documents for the Unit #2 conversion that require bidders to meet the 0.003 lb/MMBtu VOC limit in their engineering designs. Based on that information, TransAlta proposes a VOC limit of 0.003 lb/MMBtu for Unit #2 as BACT.

TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, Washington
USA 98531

T: +1 (360) 736-9901
www.transalta.com

Identification of Specific Work Practice Standards for Auxiliary Boiler and Water Bath Heaters

With respect to boilers and heaters that only burn natural gas, a consistent work practice standard is a regular boiler maintenance consistent with manufacturer's specifications. As those units are not yet specified, TransAlta will provide Ecology with the manufacturer's maintenance specifications once selected.

The boiler/heater maintenance and tune-up activity would be summarized in a maintenance log that includes the date of the tune-up and any actions taken as a part of the tune-up.

Please contact me at Conrad_Wieclaw@transalta.com or (360) 807-8093 if you have any questions on this incompleteness letter response.

Yours truly,

TRANSALTA Centralia Generation LLC
By its Manager, TRANSALTA CORPORATION

Conrad Wieclaw

CONRAD WIECLAW
Sr Manager, Engineering & Environment

EXHIBIT 106

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026



Table of Contents

Preface 3
About This Assessment 4
Reading This Report 5
Executive Summary 6
Capacity and Energy Risk Assessment 6
Trends and Reliability Implications 9
Recommendations 10
Capacity and Energy Risk Assessment 12
Assessment Approach 12
Risk Categories 12
Resource and Demand Projections 23
Reducing Resource Capacity and Energy Risk 24
Demand Trends and Implications 25
Demand and Energy Projections 25
Reliability Implications 29
Resource Mix Changes 30
Planned On-Peak Capacity Additions 31
Transmission Development and Interregional Transfer Capability 37
Transmission Projects 37
Interregional Transfer Capability Study (Canadian Analysis) 38
Regional Assessments Dashboards 41
MISO 42
MRO-Manitoba Hydro 49
MRO-SaskPower 54
MRO-SPP 59
NPCC-Maritimes 63
NPCC-New England 68
NPCC-New York 74
NPCC-Ontario 80
NPCC-Québec 86
PJM 90
SERC-Central 95
SERC-East 102
SERC-Florida Peninsula 112
SERC-Southeast 120
Texas RE-ERCOT 128
WECC-Alberta 134
WECC-Basin 138
WECC-British Columbia 143
WECC-California 147
WECC-Mexico 151
WECC-Northwest 154
WECC-Rocky Mountain 159
WECC-Southwest 163
Demand Assumptions and Resource Categories 167
Methods and Assumptions 171
Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area 175
Recommendations and ERO Actions Summary 177

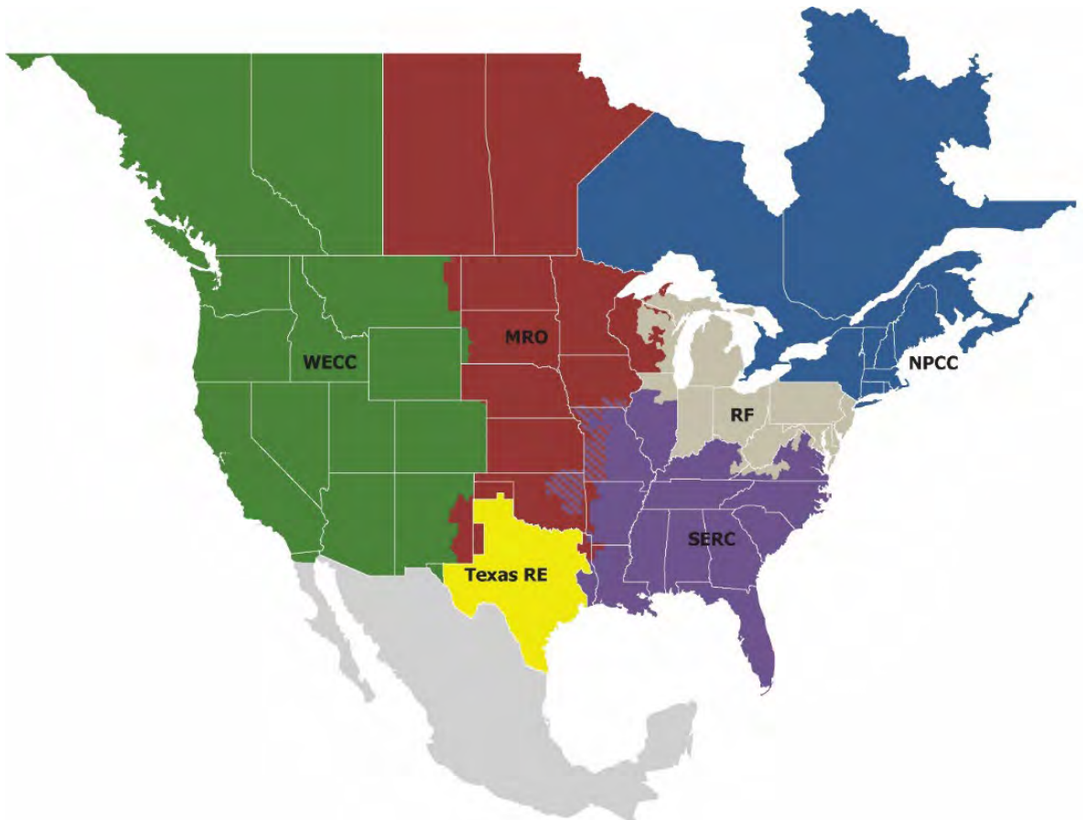
Preface

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 made up of 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 is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

The *Long-Term Reliability Assessment* (LTRA), along with NERC's other reliability assessments and analysis reports, supports the ERO Enterprise vision and mission by providing independent analysis of reliability risks. Other important assessments and reports include the following:

- **Seasonal Reliability Assessments:** The *Summer Reliability Assessment* (SRA) and *Winter Reliability Assessment* (WRA) provide overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected seasonal peak demands. They also identify reliability issues of interest and areas of concern for the upcoming season. Seasonal assessments are published annually prior to each respective season.
- **Special Reliability Assessments:** In addition to the long-term and seasonal reliability assessments, NERC also conducts special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or governmental authorities. Special reliability assessments are performed and published on an as-needed basis.
- ***State of Reliability* Report (SOR):** The SOR contains an unbiased, data-driven look at BPS reliability for the calendar year, identifying ongoing challenges and informing future-looking reliability assessments. It seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken, and will take, to address them. The SOR is published annually, containing analysis of BPS performance data from the prior year.
- **Event Analysis Reports:** NERC publishes reports of major system events and off-normal system occurrences as one output of the ERO Event Analysis Program. This program employs rigorous post-event analysis and promotes broad understanding of the causes and effects of reliability events. NERC also publishes Lessons Learned for industry.

Reliability assessments and analysis are published on NERC's website.

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the LTRA annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2025 about known system changes with updates incorporated prior to publication. This *2025 LTRA* assessment period includes projections for 2026–2035; however, some figures and tables examine data and information for the 2025 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment, which is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through its Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry and government partners.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

Assumptions

In this *2025 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts that were submitted and validated in July 2025. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been included where appropriate.
- Peak demand is based on average peak weather conditions and forecasted economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, known planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading This Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability, with a special focus on adequacy in the first five years
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[5] ERO Reliability Assessment Process Document

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

The overall resource adequacy outlook for the North American BPS is worsening: In the *2025 LTRA*, NERC finds that 13 of 23 assessment areas face resource adequacy challenges over the next 10 years. Projections for resource and transmission growth lag what is needed to support new data centers and other large loads that drive escalating demand forecasts. Most new resources in development to come on-line in the next five years consist of battery storage and solar photovoltaic (PV), which are inverter-based and weather-dependent resources that increase the complexity of planning and operating a reliable grid. Meanwhile, more fossil-fired generator retirements loom in the next five years, reducing the amount of generation that has fuel on site and impacting the system's ability to respond to spikes in demand. The continuing shift in the resource mix toward weather-dependent resources and less fuel diversity increases risks of supply shortfalls during winter months. As Resource Planners, market operators, and regulators grapple with steep increases in demand and swelling resource queues, they face more uncertainty, adding to the already-complex endeavor of planning for resource adequacy during this period of rapid grid transformation. To ensure there are sufficient resources for supplying electricity in the future and to reliably meet the growing electricity needs for North Americans, industry, regulators, and policymakers need to be vigilant for shifting projections, keep plans for deactivating existing generators flexible, expedite system development, and perform robust adequacy assessments of future scenarios. In addition, careful planning and broad cross-sector coordination will be needed to navigate a period of potentially strained electricity resources.

The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions based on current BPS planning forecasts. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used a probabilistic assessment and a deterministic reserve margin analysis from the LTRA process to identify the risk of future electricity supply shortfall and determine a risk category for each assessment area based on consistent risk criteria.[7] Risk assessment inputs are tied to industry forecasts of electricity supplies, demand, and transmission development, providing a forward-looking snapshot of resource adequacy.

Areas determined to be **High Risk** exceed the upper risk criteria levels. In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load.[8] **Elevated-Risk** areas meet resource adequacy criteria, but planned resources are likely to result in energy shortfalls that are expected to be limited to more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, fuel supply disruptions, and limitations of normal electricity transfers. **Elevated-Risk** areas are identified in the LTRA when unserved energy and load loss metrics are below the **High-Risk** criteria but are not negligible. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions and are below the lowest risk criteria level. The results of the risk assessment are summarized for all elevated- and high-risk assessment areas in **Figure 1** and described in **Table 1**.

[7] In some cases, NERC modified the risk category when system studies performed by a system operator or regulator determine that resource adequacy target(s) will not be met. Details of the risk evaluation for each assessment area are in the **Capacity and Energy Risk Assessment**.

[8] The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities, traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics. See **Risk Categories** in this report for a complete description.

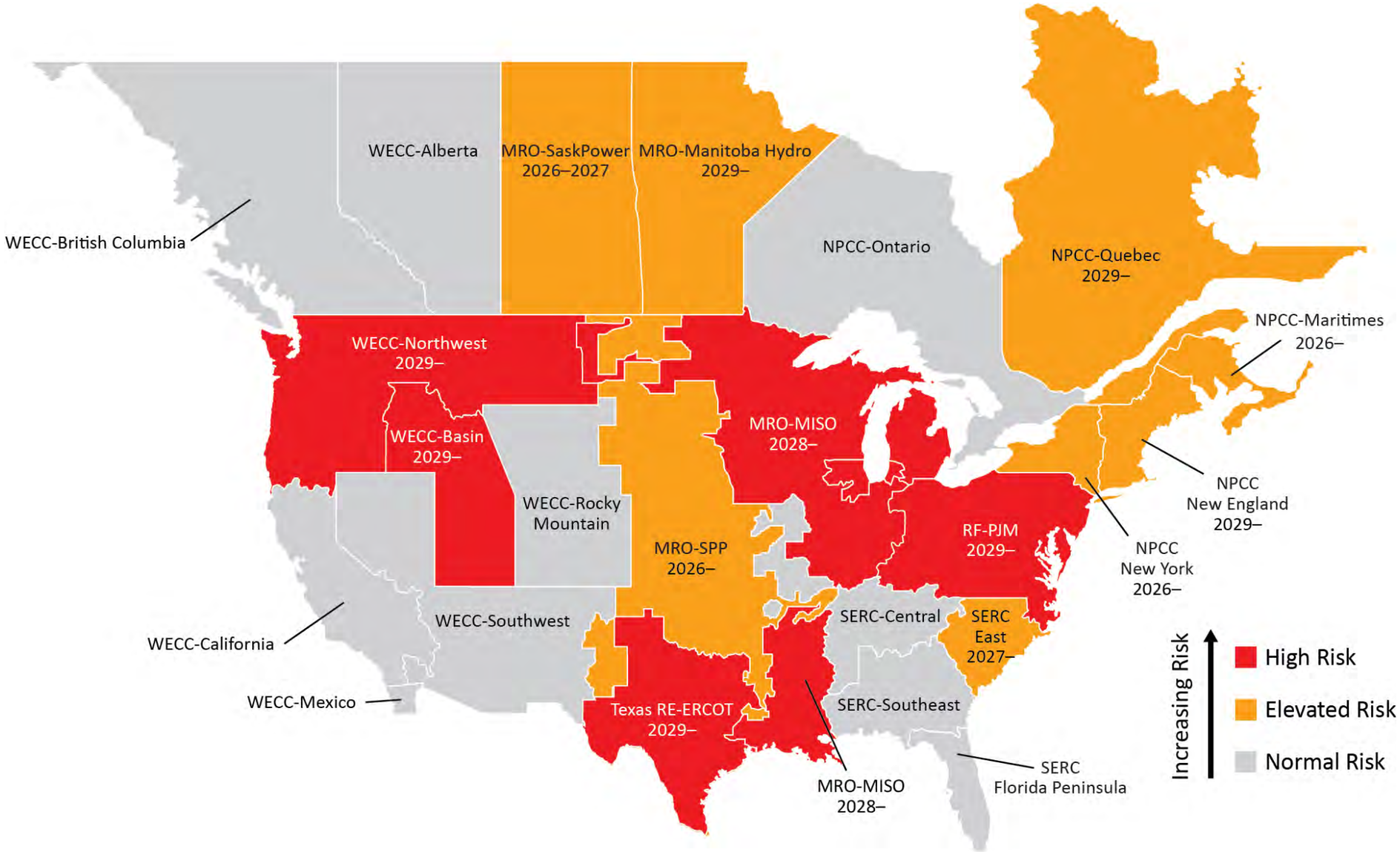


Figure 1: Risk Area Summary 2026–2030

Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

Table 1: Capacity and Energy Risk Assessment Area Summary

Assessment Area	Risk Level (High, Elevated, or Normal)					Risk Summary
	2026	2027	2028	2029	2030	
MISO						Projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements. The recently approved *Expedited Resource Addition Study* (ERAS) process 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*. Timely implementation of ERAS resources will eliminate reserve margin shortfall and improve expected unserved energy metrics.
MRO-Manitoba						With rising demand, planned reserves are falling, leading to potential resource shortfalls in low-hydro conditions.
MRO-SaskPower						With current resources, there is risk of insufficient generation during fall and spring when more generators are undergoing maintenance. Expected natural-gas-fired generator additions in Winter 2027 will boost planned reserves and reduce risks of unserved energy.
MRO-Southwest Power Pool (SPP)						Demand forecasts outpace resource additions, leading to falling reserve margins. Scenarios with low wind and high generator forced outages identify energy shortfall risks. SPP's *Expedited Resource Adequacy Study* is attracting additional resources.
NPCC-Maritimes						Demand growth forecasts have increased since the *2024 LTRA*, while expected capacity contributions from variable energy resources (VER) have declined, causing resource shortfalls in the near term. New natural-gas-fired generation planned for 2028 will reduce the potential unserved energy, but not below the elevated risk threshold.
NPCC-New England						Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of energy shortfalls in extreme winter conditions.
NPCC-New York						Planned retirements of peaking generators create localized system adequacy needs as described in the New York ISO *2025 Q3 Star Report*.
NPCC-Québec						Demand growth projections are outpacing planned resource additions, leading to projected resource shortfalls in the winter season.
PJM						Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the LTRA risk analysis.
SERC-East						Current projections for resource additions do not keep pace with escalating demand forecasts and planned generator retirements. With projected resources, supply shortfalls would occur in below-normal winter temperatures, resulting in unserved energy.
Texas RE-ERCOT						Probabilistic unserved energy metrics for 2026–2027 have improved since the *2024 LTRA*, but continued rapid load growth outpaces projected resource additions in later years. To mitigate increasing resource adequacy risks from load growth, Texas lawmakers have granted ERCOT operators additional authority to curtail new large loads if necessary to prevent grid emergencies. Texas lawmakers also established funding programs to expedite new resources that address reliability needs.
WECC-Basin						Demand forecasts outpace resource additions and expected generator retirements, leading to falling reserves. Resource additions nearing completion are predominantly solar PV, leading to a more variable resource mix. Unserved energy risk is in summer.
WECC-Northwest						Rapid forecasted demand growth is driving the need for more resources. Resource additions nearing completion are predominantly solar PV, battery, and wind, leading to a more variable resource mix. Periods of unserved energy are projected for both summer and winter.

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 23 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Responding to Trends in Resource Adequacy

As resource adequacy concerns have expanded and grown more acute in many parts of the North American BPS, more actions have been taken by industry and regulators to bolster resources.

- Projected retirements have shrunk from the *2024 LTRA*. Growing demand, market signals, and resource plans have highlighted the potential need to keep resources on-line longer than previously anticipated. Though the confirmed and announced potential retirements over the next 10 years remain high and total over 105 GW in peak seasonal capacity, this is roughly 10 GW lower than the 10-year retirement projections last year.
- The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Market procurements are becoming more effective in procuring resources as a result.
- Expedited resource programs that were approved by FERC in late Summer 2025 for MISO, PJM, and SPP have resulted in acceleration and prioritization for resources that can address identified reliability risks. Most new resources brought in through recently approved expedited resource programs are not included in the *2025 LTRA* risk assessment.
- Lawmakers in Texas have provided ERCOT with curtailment management authority over new large loads to prevent grid emergencies and established funding to speed new generating capacity to the grid.

The **Capacity and Energy Risk Assessment** and **Regional Assessments Dashboards** sections provide details on these examples and initiatives in other assessment areas.

Trends and Reliability Implications

Demand, resource, and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends and Implications

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections. New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.

Demand and large-load projections throughout the LTRA are based on load-serving entity (LSE) and BPS system planner forecasts provided to NERC during LTRA development, reflecting mid-2025 plans. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Still, large loads inherently add volatility to load forecasts as project timelines and commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions. ERCOT and PJM, the grid planners and operators for two areas experiencing vigorous large-load and data center development, have each prepared revised load forecasts since the *2025 LTRA* data collection period that, due to timing, is not used in this LTRA. Both forecasts indicate that some large-load projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Load forecasts that are revised downward can shrink the energy shortfalls that are projected in this LTRA.

Resource Additions and the Changing Resource Mix

The shift toward a more variable resource mix continues, as battery, solar PV, and hybrid generation lead the most recent and projected near-term additions and as fossil-fired generators retire. From 2024 to 2025, the existing capacity from fossil-fueled generators fell by 21 GW, while BPS capacity for peak demand hours from battery, wind, and solar resources increased by 23 GW.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown modestly since

the *2024 LTRA* by 7 GW (1.7%). This is slightly less than in the prior year when Tier 1 and Tier 2 capacity grew by 44 GW.

As older fossil-fired generators retire and are replaced by more battery and solar PV resources, the resource mix is becoming increasingly variable and weather-dependent. The share of VERs in the existing BPS on-peak resource capacity increased from 9.5% to 10.2% over the last year. VERs have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. Frequency response, or the ability of the BPS to maintain stable frequency, is one such ERS that NERC assesses on an Interconnection basis to ensure future resource mix reliability. Battery storage can enhance system frequency response. Other IBRs provide little or no frequency response capability, requiring grid operators to ensure that enough synchronous generators and other facilities are on-line for system stability. This year's LTRA finds that the future resource mix in each Interconnection through 2027 has sufficient resource types to provide for adequate frequency response. As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

The thermal generation component of the resource mix is increasingly reliant on natural gas for fuel as new natural-gas-fired generators are added to the BPS and as some existing coal-fired generators undergo fuel conversion. Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years: 53 GW of new natural-gas-fired winter capacity is in the planning queues, and new ERAS programs will add more. As new natural-gas-fired generators progress through interconnection processes, Generator Owners, grid planners, and natural gas infrastructure developers need to take steps to ensure that regional natural gas infrastructure can reliably serve the needs of BPS generators.

Transmission Development and Interregional Transfer Capability

Transmission projections reported for the *2025 LTRA* reflect an increase in transmission development, continuing a trend that emerged in the *2024 LTRA*. This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially over past-year levels; rather, the large increase in transmission projects is seen in planning phases. Several Planning Coordinators (PC) have recently approved, or are actively contemplating, expansive extra-high voltage (EHV) overlays on their systems to address new generator additions and a variety of reliability needs, including Hydro-Québec, ERCOT, SPP, MISO, PJM, BC Hydro, and the Independent Electricity System Operator (IESO) in Ontario.

Interregional transmission projects that support energy transfers across Interconnections make up a small but important portion of total BPS transmission development. They can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[9] including scenarios identified in the *Interregional Transfer Capability Study* (ITCS) published by NERC in 2024, and the separate ***Interregional Transfer Capability Study (Canadian Analysis)***. About 4% of transmission projects reported for the *2025 LTRA* are for tie-lines that support transfers between neighboring systems, lower than the 6% reported in the *2024 LTRA*.

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays. Other reasons for delays include economic impacts, planning and construction issues, permitting issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Expedite new resources to meet growing demand and carefully manage generator deactivations.** BPS planners should develop, implement, or enhance mechanisms to expedite resource additions to the grid that provide the services needed to address anticipated reliability issues related to each area's needs. Independent System Operator/Regional Transmission Organizations (ISO/RTO) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulators must support resource development and manage the pace of retirements such that replacement infrastructure can be developed and placed in service to support reliability needs.
2. **NERC, industry, and regulators: Understand and manage reliability risks accompanying large-load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress.** An increasing number of large commercial and industrial

[9] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission

loads is rapidly connecting to the BPS. Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications) and hydrogen fuel plants—present unique challenges in BPS planning and operations. Stakeholders should support NERC's Large Loads Action Plan[10] and collaborate through NERC's Large Loads Task Force.[11] ISO/RTOs should collectively work to create more uniform requirements to address the emerging reliability issues associated with large data center loads.

3. **NERC, Regional Entities, and industry: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To promote consistency in analysis and develop assessment capabilities, NERC and the Regional Entities piloted Interconnection-wide energy assessments using a common probabilistic resource adequacy tool in 2025. Wide-area energy analysis will support the evaluation of interregional transfer capabilities and the effects of extreme weather and regional fuel supply issues on the BPS at an Interconnection level. Industry should work with NERC through its technical groups to implement ERO energy assessments in the *2026 LTRA* and continue to improve consistency in the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy.

4. **Regulators and policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, many states are also taking steps to expedite siting and permitting. Siting and permitting issues are among the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

5. **Regulators, electric industry, and gas industry member organizations: Continue identifying and implementing solutions for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** As various initiatives launched in past years roll out recommendations for addressing reliability needs, stakeholders should act with urgency on implementation. Continued collaboration through readiness forums and working groups remains a priority. While new regulatory and oversight mechanisms of the natural gas industry have yet to solidify, voluntary actions for managing natural gas production, processing, and delivery risks are needed. NERC, gas and electric industry, and research partners should continue studies and assessments of regional fuel supply risks to BPS generation.

6. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure that ERSs are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[12] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including VERs; however, policies and market mechanisms need to reflect these requirements to ensure that these services are provided and maintained. ISO/RTOs and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary.**

[10] NERC's Large Loads Action Plan: https://www.nerc.com/initiatives/large-loads-action-plan
[11] NERC's Large Loads Task Force webpage: Large Loads Task Force (LLTF)
[12] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Risk Assessment

Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure that sufficient resources are available to meet demand and prevent unacceptable levels of energy shortfall. In their application, traditional capacity-based adequacy criteria were not designed to consider the magnitude, frequency, duration, and timing of potential energy shortfalls. Such considerations have become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. NERC's LTRA includes all-hours probabilistic indices to measure these additional dimensions of risk and provide a more complete analysis to inform system plans.

Assessment Approach

NERC evaluates industry-provided resource adequacy data and credible studies to assess risks of future energy shortfalls as the system is currently planned. Probabilistic and deterministic analyses provide forward-looking snapshots of resource adequacy tied to industry forecasts of electricity supplies, demand, and transmission development. The risk analysis entails these components:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high risk periods and potential energy constraints resulting in load-loss events. The 2025 ProbA is performed for each assessment area and examines the system as planned for the years 2027 and 2029. Loss-of-load hours (LOLH) and expected normalized unserved energy (NEUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as the Reference Margin Level (RML)) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

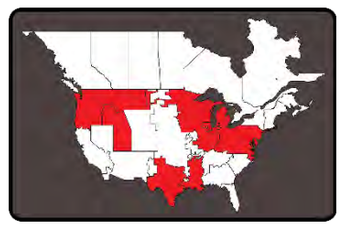
NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

The risk determination is based on data and information provided to NERC during LTRA development and represents a snapshot in time. Integrated resource planning and ISO/RTO resource adequacy mechanisms vary across North America and can be implemented to respond to resource adequacy issues on many different timescales.

The **Demand Assumptions and Resource Categories** section provides further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

For the *2025 LTRA*, NERC uses the following three levels of risk category determination for each assessment area and associated years for which there is a risk of energy shortfall during the first five years of the LTRA period (i.e., 2026–2030). The details for the risk criteria determination are shown below for each category of risk.



An assessment area is determined as **High Risk** when established resource adequacy targets or requirements are not met or when probabilistic or deterministic energy analyses find that planned resources produce shortfalls resulting in unserved energy or load loss exceeding criteria for baseline resource adequacy specified below. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun to consider or develop resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[13] High risk areas are those where today's demand forecasts and resource projections indicate a shortfall in future planned resources for expected (i.e., most likely, aka 50/50) demand and typical resource performance. More severe operating conditions associated with unusual heat waves or deep-freeze events would further exacerbate shortfalls in planned resources.

For the *2025 LTRA*, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA; or
- Annual normalized expected unserved energy (EUE) exceeds 0.002% (20 ppm) for one or more years in the ProbA; or

[13] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Resource adequacy target(s) established by regulatory authority or system operator are not met.

Resource Planners, regulators, and market operators in assessment areas identified as having a high risk of resource shortfalls can mitigate these risks through timely actions that address capacity and energy risks.



An assessment area is determined to have **Elevated Risk** when it meets the established resource adequacy targets and baseline criteria specified earlier but does not meet more stringent thresholds of unserved energy and load loss that provide for reliability in more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. For the *2025 LTRA*, assessment areas are classified as elevated risk when they meet any one of the following criteria in the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA
- Annual normalized EUE is less than 0.002% (20 ppm) but greater than or equal to 0.0002% (2 ppm) for one or more years in the ProbA
- Resource adequacy target(s) established by regulatory authority or system operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions indicate risk of loss of load



An assessment area is determined to have **Normal Risk** if resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas determined as normal risk are expected to have sufficient resources for plausible extreme[14] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2025 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is below 0.0002% (2 ppm).
- Resource adequacy target(s) established by regulatory authority or system operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from the ProbA performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In last year's LTRA, NERC incorporated new probabilistic assessment risk criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report, *Evolving Planning Criteria for a Sustainable Power Grid*, alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

A numerical summary of the assessment areas' risk profile measured against the NERC risk criteria is summarized in **Table 2**. A risk description summary for each assessment area at an **Elevated Risk** or a **High Risk** is provided in the **High-Risk Area Details** or **Elevated-Risk Area Details** sections following **Table 2**. Full details about all assessment areas are provided in the **Regional Assessments Dashboards** section.

[14] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide-Area Heat Dome.

Table 2: Capacity and Energy Risk Assessment Numerical Summary														
	NEUE (ppm)		LOLH (hours/year)		Anticipated Reserve Margin					Reference Margin Level[15]				
Summer-Peaking Areas	**2027**	**2029**	**2027**	**2029**	**2026**	**2027**	**2028**	**2029**	**2030**	**2026**	**2027**	**2028**	**2029**	**2030**
MISO	1.13	**42.39**	**0.23**	**6.61**	11.0%	11.2%	9.5%	8.6%	**4.3%**	8.1%	8.3%	8.5%	8.5%	8.5%
MRO-SPP	0.00	0.00	0.00	0.00	32.4%	30.3%	28.4%	25.1%	22.6%	19.0%	19.0%	19.0%	19.0%	19.0%
NPCC-New England	0.00	0.02	0.00	0.00	18.3%	21.7%	24.8%	23.7%	23.6%	13.4%	13.0%	13.0%	13.0%	13.0%
NPCC-New York	0.00	0.08	0.00	0.03	22.3%	24.5%	24.5%	23.6%	22.5%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	0.00	0.00	0.00	0.00	29.6%	19.8%	28.1%	18.7%	19.7%	16.1%	19.0%	22.6%	15.8%	19.5%
PJM	**3.50**	**65.50**	**0.61**	**9.97**	29.7%	28.3%	24.3%	**18.9%**	**13.9%**	18.6%	20.1%	21.9%	23.9%	26.3%
SERC-Central	0.00	0.00	0.00	0.00	19.1%	20.8%	19.7%	18.5%	16.5%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-East	0.98	**2.27**	**0.15**	**0.33**	30.6%	30.5%	30.5%	31.5%	34.9%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Florida Peninsula	0.00	0.00	0.00	0.00	27.4%	25.2%	24.3%	22.6%	21.1%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Southeast	0.00	0.00	0.00	0.00	35.9%	29.5%	29.8%	24.9%	20.9%	15.0%	15.0%	15.0%	15.0%	15.0%
Texas RE-ERCOT	**8.70**	**18.84**	**0.95**	**3.64**	28.2%	30.5%	31.8%	30.8%	29.9%	13.8%	13.8%	13.8%	13.8%	13.8%
WECC-Basin	0.04	**2,250**	**3.00**	**310.00**	36.3%	37.9%	27.4%	19.7%	15.2%	13.5%	14.0%	13.6%	12.4%	12.3%
WECC-California	0.00	0.00	0.00	0.00	53.2%	47.0%	46.1%	45.6%	42.7%	20.3%	19.2%	19.3%	19.7%	19.3%
WECC-Mexico	0.00	0.00	0.00	0.00	14.9%	13.8%	29.9%	27.0%	24.6%	7.8%	8.0%	9.1%	7.2%	7.0%
WECC-Rocky Mountain	0.00	0.00	0.00	0.00	51.3%	60.0%	53.2%	38.1%	30.5%	17.8%	17.0%	16.2%	16.1%	15.7%
WECC-Southwest	0.00	0.00	0.00	0.00	41.1%	39.6%	38.6%	38.4%	36.1%	13.3%	13.7%	13.6%	12.6%	12.2%
Winter-Peaking Areas	**2027**	**2029**	**2027**	**2029**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
MRO-Manitoba Hydro	0.12	0.23	0.03	0.06	13.9%	16.7%	15.4%	13.6%	**1.2%**	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	**5.24**	0.19	**1.09**	0.05	25.9%	35.0%	33.4%	32.3%	31.2%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Maritimes	0.52	0.25	**0.25**	0.10	**17.2%**	**18.5%**	25.6%	23.0%	21.7%	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-Québec	0.00	0.29	0.00	**0.11**	15.6%	16.7%	14.7%	13.0%	**11.5%**	11.9%	12.2%	12.2%	12.2%	12.2%
WECC-Alberta	0.00	0.00	0.00	0.00	36.2%	45.3%	40.7%	38.0%	33.0%	11.8%	17.6%	14.3%	15.6%	11.6%
WECC-British Columbia	0.00	0.00	0.00	0.00	23.4%	19.1%	19.5%	24.1%	24.2%	11.7%	12.1%	12.1%	11.6%	11.6%
WECC-Northwest	0.00	**36.64**	0.00	**85.00**	30.2%	29.3%	23.3%	19.1%	15.7%	17.8%	17.4%	16.1%	15.8%	15.5%

[15] Refer to the Regional Assessments Dashboards and the Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area table.

High-Risk Area Details

The assessment areas below exceed the highest level of risk criteria for the **High-Risk** classification during one or more years of the 2026–2030 period. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO (Normal Risk 2026| Elevated Risk 2027| High Risk 2028–)

Escalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area. MISO forecasts its peak total internal demand at 127 GW during the 2026 summer season (up over 2.6 GW since the same year's projection in the *2024 LTRA*) and expects that summer demand will grow to 143.7 GW by 2035. The largest contributor to this accelerated demand growth is data center additions with 18 GW of data center loads projected by 2035. MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements. New solar PV resources contribute to a 5.7 GW increase in MISO's accredited non-thermal capacity since last year.

As of July 2025, MISO has more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity. In addition to these resources, MISO instituted the ERAS process to respond to generation needs. The ERAS process provides a framework for the accelerated study of generation projects that address urgent resource adequacy and reliability needs in the near term. ERAS projects are not in the model for the *2025 LTRA*. If ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated.

Based on the current resource and demand forecasts, MISO begins to meet elevated-risk criteria in 2027 (see **Table 3**). While resources are adequate for regulatory requirements, the ProbA results show load loss and unserved energy exceeding the elevated-risk threshold. The Summer season makes up the bulk of annual risk in this region and is seen to materialize during late afternoon and evening hours when demand is high and solar resource output begins to decline. The ProbA also identifies winter risk periods during early morning and hours after 7:00 p.m. Additionally, shortfall 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.

As the demand forecast rises in subsequent years, and with currently projected generator retirements and planned resource additions, the ProbA shows worsening results. While resources are adequate for regulatory requirements (i.e., loss of load expectation (LOLE) of 0.1 day in a year), the ProbA results show load loss and unserved energy exceeding the elevated risk threshold criteria.

For the 2029 ProbA study, MISO assumed 14 GW of generator retirements that are uncertain to occur by 2029.

Table 3: MISO Base-Case Summary of Results

	2027	2029
EUE (MWh)	797	31,654
NEUE (ppm)	1.13	42.39
LOLH (hours per Year)	0.23	6.61
Category	Elevated	High

With model assumptions, MISO would exceed load-loss and unserved energy criteria and fall below reserve margin targets to become a high-risk area beginning in Winter 2028 (see **Figure 2**). Projections for resource additions are predominantly solar PV, with some battery and wind resources. The small amounts of natural-gas-fired generation in signed interconnection agreements do not offset planned generator retirements, and, as a result, MISO is projecting shortfalls in planned resources for winter peak periods.

These results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and can work to address uncertainties associated with these three phenomena.

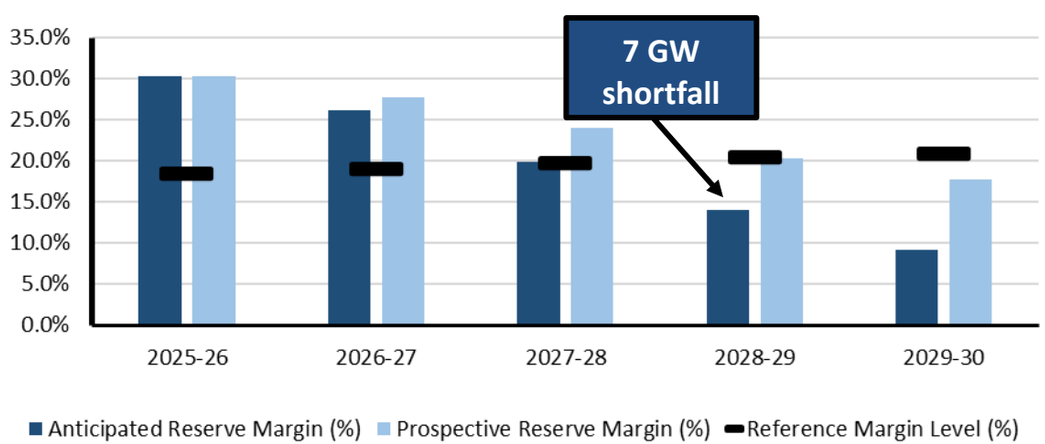
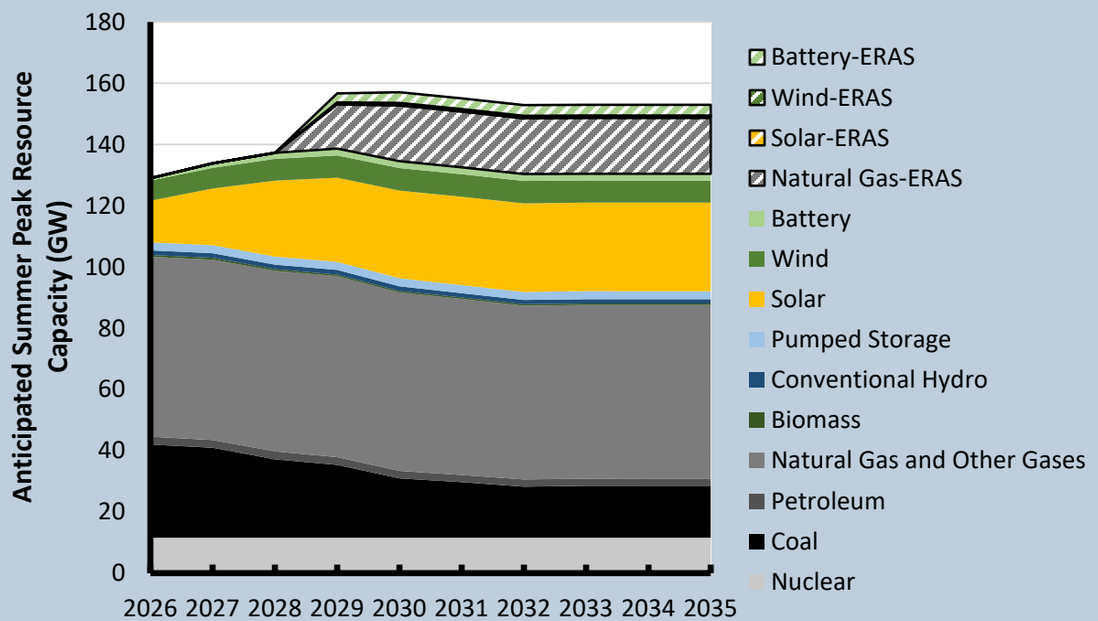


Figure 2: MISO Winter Planning Reserve Margins

Currently, MISO has surplus transfer capacity within its assessment area, but transfers between subregions have been historically constrained by a transmission limitation between the northern and southern MISO subregions.

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*, and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity

PJM (Elevated Risk 2026–2028/ High Risk 2029–)

Demand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads. PJM expects its summer peak demand to grow by 56 GW to a total of 210 GW in 2035, and its winter peak demand is expected to climb by 62 GW to reach 198 GW by winter 2034–35. PJM's annual net energy for load growth rate is projected to average 4.8% per year over the next 10 years, up from 2.3% in last year's projections.

At the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays. A large share of PJM's new interconnection requests is from VERs, approximately 40% of which are solar, and dispatchable resources are currently leaving the system faster than they can be replaced with other dispatchable technologies. These factors, paired with PJM's limited reliance on transfers from neighboring areas to meet resource adequacy targets (maximum total transmission interchange capability is <2% of PJM's internal generation capacity), have led to a projection that PJM's ARM may fall below its Installed Reserve Requirement (or RML) in 2029 (see **Figure 3**).

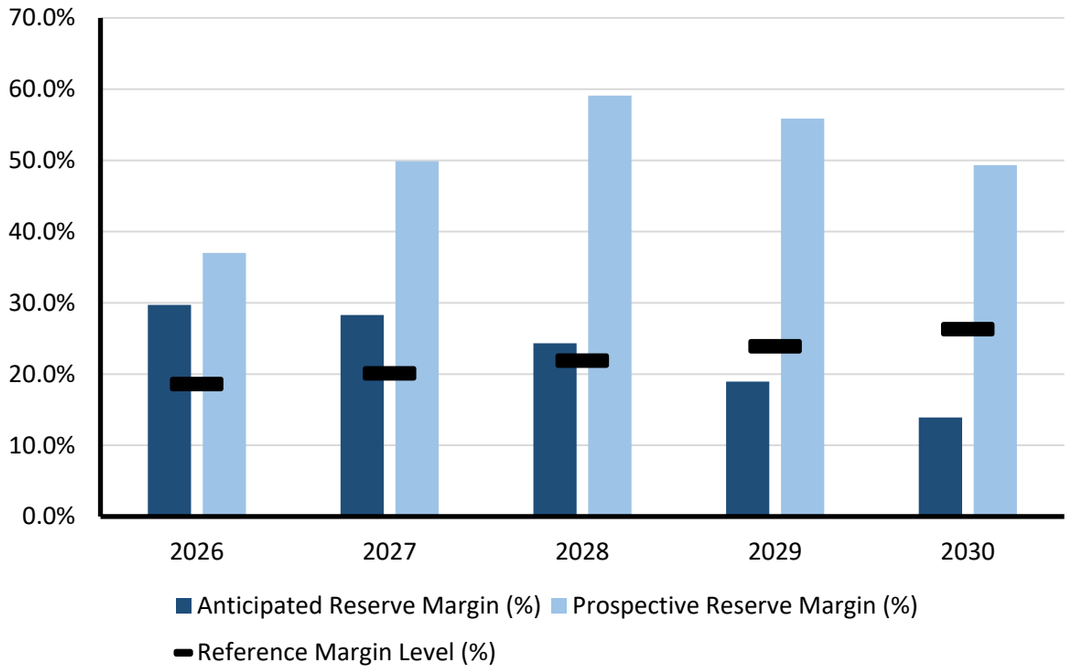


Figure 3: PJM Summer Planning Reserve Margins

As part of its reforms to speed interconnection with the system, PJM has approximately 30,000 MW of generation projections in the transitional interconnection queue to be processed in 2026. PJM's new cycle process opens in April with a one- to two-year timeline for reviews, depending on the impact to the system. From the time of the original *2025 LTRA* data submittal to recent evaluation, PJM projected an additional 8.3 GW of Tier 1 summer resource capacity over the next seven years. Tier 1 resource additions will provide 3.4 GW of winter capacity. However, many of these projects continue to be slowed or stopped by factors affecting multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges or financing.

In 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative (RRI), which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. This net increase factors resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

Setting aside the impact of such initiatives, results of the ProbA using PJM's current resource and demand forecasts indicate that the area is at an elevated risk of resource shortfalls at the beginning of the 10-year horizon (see **Table 4**). Because this year's ProbA does not study years earlier than 2027, the elevated-risk determination is based on results of the 2024 ProbA and consideration of the declining ARM in PJM since last year's LTRA (2026 Summer ARM has fallen from 35.7% to 29.7%). The greatest risk of resource shortfalls leading to unserved energy or load loss in PJM occurs in the winter months during the early morning and evening hours. The risk is associated with generator availability and performance issues that can arise from equipment freezing and fuel supply issues during extreme winter conditions. PJM falls into the high-risk category beginning in 2029 as demand forecasts continue to climb, generators reach planned retirement dates, and the projected resources become less certain. The winter risk profile indicates that new resources will need to be capable of reliably serving winter load.

Table 4: PJM Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	538	3,251	67,581
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.1	0.61	9.97
Category	Elevated	Elevated	High

***Provides the 2024 ProbA Results for Comparison**

Texas RE-ERCOT (Elevated Risk 2026–2028| High Risk 2029–)

The Texas RE-ERCOT assessment area is forecast to experience continued rapid electric demand growth over the next 5–7 years. ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads totaling 45 GW by 2030, of which 23 GW are data centers.

ERCOT continues to evolve its planning methods as fluctuations in recent large interconnections activity continue to affect both near- and long-term demand expectations. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Such fluctuations do not, however, undercut the significance of demand growth attributable to large loads.

Responding to rapidly escalating demand from data centers and other large industrial loads, ERCOT, regulators, and lawmakers in Texas are adapting with policy and planning approaches to address emerging supply risks. Actions provide ERCOT with new curtailment management tools for large loads, establish criteria for when to incorporate new large loads in system planning, and help fund and speed new generating capacity to the grid. Furthermore, the first reliability assessment for the Public Utility Commission of Texas (PUCT)-approved Reliability Standard, and potential approval of market design changes to address deficiencies, is scheduled for completion by year-end 2026. Such market design changes would further mitigate energy risk.

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and provide ERCOT authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. For the *2025 LTRA*, ERCOT's DR contributions have increased substantially to reflect the authority and capability to curtail new large loads during energy emergencies. For Summer 2026, DR contributes 13.3 GW to resource adequacy (up from the 2.7 GW projection in the *2024 LTRA*), and contributions from DR rise to 53.1 GW by 2030. Because new large loads can be curtailed during energy emergencies, the rapid rise in projected large loads has substantially less effect on Planning Reserve Margins in ERCOT than in the 2024 LTRA.

The ARM is above the 13.75% RML for all years (see **Figure 4**).

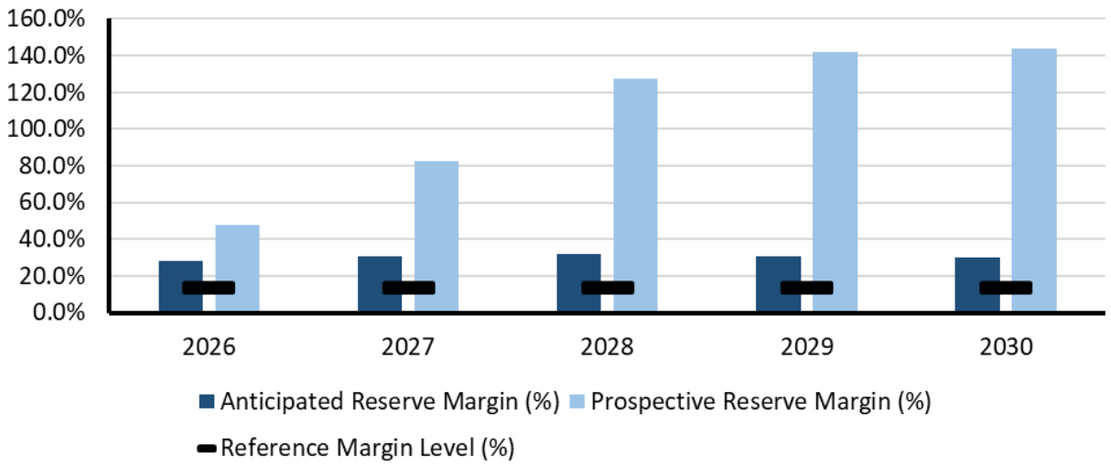


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

ERCOT's Planning Reserve Margins in the *2025 LTRA* are also being affected by the implementation of new capacity contribution methods. ERCOT has switched from using historical average on-peak capacity factors to average effective load carrying capabilities (ELCC) for VERs, and the resulting capacity derates largely offset the gains that load management programs have on ARM. In the case of solar, ELCCs are significantly lower than prior years. ELCC values are probabilistically derived and reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low.

The ProbA results for Texas RE-ERCOT reveal some improvement in near-term resource adequacy when compared to the *2024 LTRA*, but the area remains an elevated risk through 2027 before forecasted load growth drives the area to high risk (see **Table 5**). ERCOT's ProbA modeling includes demand-side management protocols that reasonably reflect large load curtailments described above, and other programs used in ERCOT's market. This modeling contributes to the improved unserved energy and load-loss hour metrics that are observed between the 2024 ProbA and the current ProbA. Battery resource additions since last year and improved modeling in the resource adequacy analysis tool also contribute to these improved metrics.

Table 5: Texas RE-ERCOT Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11,090	5,865	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.95	3.64
Category	Elevated	Elevated	High
***Provides the 2024 ProbA Results for Comparison**			

ERCOT's ProbA study results show that most resource adequacy risk is in the winter, and this is mainly driven by the large demand variability associated with winter temperatures. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year. For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours (peaking at hour ending (HE) 9:00 p.m.) based on probabilistic capacity reserve modeling for monthly peak load days. During these periods, the drop-off in solar generation causes margins to decrease when load remains high. Battery storage helps reduce these short-duration energy risks. ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026 (Existing and Tier 1 resource categories) and grow to 25.2 GW by 2029. ERCOT typically sees the greatest energy provided by energy storage during net load peaks when solar is ramping off in the evening, or during early morning hours prior to solar ramping up.

In response to the rapid and unprecedented load growth, the PUCT in April 2025 approved three 765 kV import paths identified in the *Permian Basin Reliability Study*, which introduced the new 765 kV voltage class into the ERCOT region after six decades since the introduction of the 345 kV voltage class. The Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP) tackles the unprecedented load growth expected by 2030 and enhances transfer capability by an additional 600 MW to 3,000 MW. This 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers.

WECC-Basin (Elevated Risk 2026–2028/High Risk 2029–)

Forecasted load growth and planned generator retirements in the Great Basin (WECC-Basin assessment area) present resource adequacy challenges. Over the next 10 years, the summer demand forecast will rise by over 1.7 GW (17%, or 1.8% compounded annually), while at the same time the capacity from currently existing resources will decline by nearly 2.3 GW through generator retirements and other capacity changes. Solar resources are the predominant type nearing project completion: There is 3.5 GW of nameplate solar capacity (capable of providing 2.3 GW to summer capacity) in Tier 1 resources for the assessment period, making up nearly half of all resources in the

Tier 1 and Tier 2 planning.[16] The projected resources, with planned retirements and additions, are not sufficient for forecasted demand, resulting in some unserved energy and load-loss hours in the future-year energy analysis. While the ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH (see Table 6).

Table 6: WECC Basin Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2,250.70
LOLH (hours per Year)	N/A	3.00	310.00
Category	-	High	High
***No prior results as the assessment area is new for the *2025 LTRA*.**			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. ProbA results for 2027 indicate that risk is most concentrated to the month of peak demand and the hours around sunset as solar output declines. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime. In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in unserved energy and load-loss hours.

Unlike the ProbA results from other areas, WECC's probabilistic model produces values higher values for load loss and EUE because the results are not probabilistic weighted averages. Taking this into account, NERC assesses WECC Basin as an elevated risk through 2029 even though the reported load-loss hours from the simulations exceed high-risk criteria

WECC-Northwest (Normal Risk 2026–2028| High Risk 2029–)

Peak load in the WECC-Northwest assessment area is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest. There are over 10 GW of new wind, solar, and battery projects expected to connect over the next five years (nameplate capacity) and provide an expected on-peak capacity contribution in winter of 3.2 GW. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging. While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029 (see Table 7).

Table 7: WECC Northwest Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0.00	36.64
LOLH (hours per Year)	N/A	0.00	85.00
Category	N/A	Normal	High
***No prior results as the assessment area is new for the *2025 LTRA*.**			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer.

Elevated-Risk Area Details

The below areas are classified as Elevated Risk as they are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the Regional Assessments Dashboards section.

MRO-Manitoba Hydro (Normal 2026–2028| Elevated 2029–)

The Winter 2026–2027 peak demand forecast grew by 127 MW, exceeding the projected 29 MW growth from the *2024 LTRA*. Demand growth is driven primarily by population growth and expected economic activity. Conversely, the forecasted annual peak demand growth rate for the next 10 years has fallen to almost 1.4%, down from around 1.8% projected in the *2024 LTRA*. Generating resources are projected to remain largely the same over the 10-year planning period.

Similar to prior probabilistic assessments, Manitoba Hydro's 2025 ProbA indicates elevated-risk levels of load loss in the later (year 4) study year (see Table 8). Resource adequacy concerns and load-loss risk in the ProbA arise from studied very low hydro conditions. Although the Manitoba system is

[16] Tier 1 resources in the LTRA are those resources in the interconnection process that have high confidence of being realized and generally under construction or have signed interconnection agreements. Tier 2 resources have more uncertainty in being realized and are in earlier development stages such as undergoing interconnection planning study.

winter-peaking, the risk is primarily present during the summer season, with some risk also identified in the spring shoulder season. Planned electricity supply resources could fall short during an extreme and prolonged drought, affecting the predominantly hydroelectric system.

Table 8: MRO-Manitoba ProbA Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	5	3	6
NEUE (ppm)	0.18	0.12	0.23
LOLH (hours per Year)	0.06	0.03	0.06
Category	Normal	Normal	Elevated
*** Provides the 2024 ProbA Results for Comparison**			

MRO-SaskPower (Elevated 2026–2027| Normal 2028–)

Large industrial loads in Saskatchewan are driving average annual peak demand growth of 1.0% compounded annually over the next 10 years, down slightly from the *2024 LTRA*'s projection (1.35%). To respond to demand growth, SaskPower recently added 370 MW of natural-gas-fired generation, 220 MW of VERs, and a 20 MW/20 MWh battery storage system to its system and is projecting on-peak resource additions of 700 MW over the next 10 years—a slight decrease from last year's projection (~1 GW). Nameplate additions include 400 MW of wind, 300 MW of solar, and 525 MW of natural gas to offset ~32 MW of confirmed waste heat recovery and wind generation retirements. Saskatchewan is also deferring generator retirements and reactivating recently deactivated coal units and is bolstering both its intra-regional and interregional transmission system to diversify its current portfolio that relies heavily on firm transfers with Manitoba. Reserve margins are expected to remain above SaskPower's RML for the entire 10-year period of the *2025 LTRA*.

SaskPower is a winter-peaking system, but MRO-Saskatchewan's probabilistic studies concluded that LOLH and EUE could occur during planned outages of large generators during peak demand hours in the spring and fall seasons. The ProbA reveals load-loss risk during the months of May, August, September, and October in 2027 based on current planned resources and load forecasts. Monthly and annual results improve in 2029 with SaskPower's projected resource additions (see **Table 9)**.

Table 9: MRO-SaskPower Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	76	145	5
NEUE (ppm)	2.81	5.24	0.19
LOLH (hours per Year)	0.55	1.09	0.05
	Elevated	Elevated	Normal
***Provides the 2024 ProbA Results for Comparison**			

MRO-SPP (Elevated 2026–)

Resource additions and delays in generator retirements since the *2024 LTRA* are improving the resource adequacy outlook for 2026, while higher demand forecasts and less capacity projects in development are causing lower planned reserves in later years. SPP's ARMs are projected to remain above RMLs until after 2030 (see **Figure 5**). Additionally, ProbA results of the planned resources and demand forecast did not identify EUE or load-loss hours in studied years. Seasonal resource adequacy assessments by NERC have identified risks of insufficient operating reserves during periods of low wind and high generator outages.[17] SPP is an elevated risk because it is projected to have lower planned reserves with a similar mix of VERs and dispatchable thermal generation in the future.

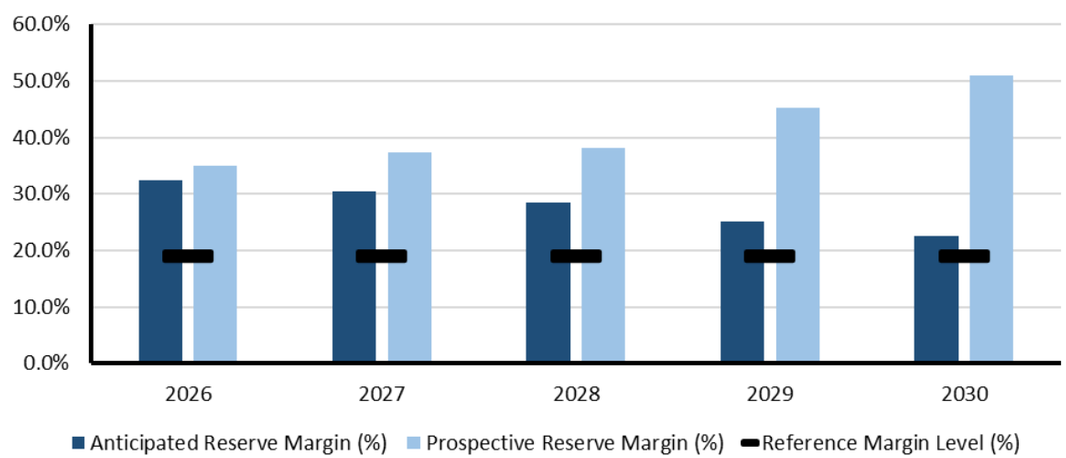


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

[17] See NERC *2025 Summer Reliability Assessment*

Recent and newly approved resource adequacy initiatives in SPP are aimed at addressing demand growth and energy challenges associated with the evolving resource mix. SPP has approved higher Planning Reserve Margin requirements for LSEs that take effect beginning in the summer of 2026, along with a new winter reserve margin requirement starting later that year. These reserve margin requirements respond to growing resource adequacy challenges by obligating LSEs to obtain more firm resources for the summer and winter seasons. New performance-based resource accreditation will more accurately account for generator contributions to serving area demand during times of greatest need. The *Expedited Resource Adequacy Study* process, approved by FERC in July, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs.

NPCC-Maritimes (Elevated 2026–)

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period (see **Table 10**). This translates to compound average growth rates of 0.8% in summer and 1% in winter, which are higher than the *2024 LTRA* projections (0.4% in summer and 0.6% in winter). Resource projections for Maritimes have diminished slightly since the *2024 LTRA* due to smaller peak capacity contributions from certain VERs through most of the planning period.

Firm capacity transfers in the first two years of the assessment period (2026–2027 and 2027–2028) decreased significantly from the *2024 LTRA* (322 MWs to -32MWs in 2026 and 215 MWs to 75 MWs in 2027). As a result, the ARM is below the 20% RML in those years, 17.2% and 18.5%, respectively. Beginning in 2028, the capacity transfers for the remaining assessment period are consistent with those in the *2024 LTRA*, and ARMs are projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

Table 10: NPCC-Maritimes Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	5	15	7
EUE (ppm)	0.17	0.52	0.25
LOLH (hours per Year)	0.09	0.25	0.10
***Results from the 2024 The ProbA simulations**			

The ProbA for 2027 indicates elevated levels of unserved energy in the peak winter month of February. Load growth projections and resource mix characteristics are the primary driver. A few hours of risk occur in other winter months. Resource additions contribute to the improved EUE and LOLH metrics for the 2029 study year.

NPCC-New England (Normal 2026 –2028| Elevated 2029–)

Since the *2024 LTRA*, 650 MW of fossil-fired generation has retired in New England, while wind, battery, and solar projects and uprating to an oil-fired power plant are projected to increase summer capacity by 1 GW in Summer 2026. Winter capacity is also increasing by a similar amount due to the expected contribution of offshore wind by winter 2026–2027. New England is among the areas projecting the highest growth in winter electricity demand, with winter peak demand forecast to increase by 7.1 GW (36%) from the Winter 2025–2026 forecast over the next 10 years. This demand forecast has changed little since the *2024 LTRA*.

ProbA results and reserve margin assessment for the NPCC-New England Assessment Area indicate that the risk of unserved energy in New England is small (see **Table 11**). Unserved energy risk is concentrated in the summer months when area demand currently peaks. However, escalating winter electricity demand and the performance challenges faced by the current and future resource mix in extreme, long-duration cold weather events is a persistent reliability concern. New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. Interstate natural gas pipelines serving New England run at full capacity with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. An extended cold spell or a series of cold spells can threaten regional natural gas fuel delivery infrastructure and result in insufficient fuel for electric generators. Dual-fueled generation provides crucial alternative energy to maintain electric system reliability. In scenarios of extended extreme cold, stored liquid fuels can become depleted and result in insufficient generation for demand.

Table 11: NPCC New England Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11	<1	2
NEUE (ppm)	0.10	0.00	0.02
LOLH (hours per Year)	0.10	0.00	0.00
Category	Normal	Normal	Normal
*** Provides the 2024 ProbA results for Comparison**			

NPCC-New York (Elevated 2026–)

The LTRA anticipated and Prospective Reserve Margins are above RML of 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the demand forecast with a greater risk added due to the variability in resource contribution. Demand could be 10–13% higher than expected, which could cause strain on the system.

This impact is shown in the increasing LOLH and EUE shown in **Table 12.**

Table 12: NPCC New York Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	2	<1	12
NEUE (ppm)	0.01	0.00	0.08
LOLH (hours per Year)	0.01	0.00	0.03
Category	Normal	Normal	Normal
*** Provides the 2024 ProbA results for Comparison**			

While NPCC's ProbA results and reserve margin assessment for the New York assessment area indicate that the risk of unserved energy in New York is relatively small, an assessment performed by NYISO, the ***2025 Quarter 3 Short-Term Assessment of Reliability*** **(STAR)**,[18] identified transmission security reliability needs in the New York City and Long Island parts of the system to ensure summer reliability. With little reliability margin, plausible futures point to system issues within the next 10 years. Depending on demand growth and retirement patterns, the system may need several thousand megawatts of new dispatchable generation over that time frame.

Due to the reliability needs identified in the STAR report, NERC assesses that NPCC-New York is an elevated risk area and that, with current resource and transmission system projections, localized supply shortfalls are likely in extreme conditions.

NPCC-Québec (Normal 2026–2028| Elevated 2029–)

Québec's demand forecast has increased since the *2024 LTRA*, driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Québec's demand peaks at 41.4 GW in 2026–2027, rising to 49.6 GWs by 2035–2036, an increase of 8.2 GWs compared to the assessment period growth of 7.5 GWs projected in the *2024 LTRA*.

With stable resources over the 10-year assessment period, Québec's ARMs remain above the 12.2% RML for the first four years, falling below in 2030–2031 and all subsequent years. Québec and Ontario have a firm seasonal capacity exchange agreement through 2030–2031 that allows Québec to import 600 MW in winter.

Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and natural-gas-fired generation. These resources are not included in the present assessment due to their early development stage but are expected to be incorporated gradually into future assessments.

Hydro Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, EUE and LOLH are above the elevated risk criteria See **Table 13**.

Table 13: NPCC Québec Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	8	8	63
NEUE (ppm)	0.04	0.00	0.29
LOLH (hours per Year)	0.01	0.00	0.11
Category	Normal	Normal	Elevated
*** Provides the 2024 ProbA results for Comparison**			

SERC-East (Normal 2026| Elevated 2027–)

SERC-East is projecting over 5.7 GW of coal unit retirements over the 10-year assessment horizon. These continued retirements from prior years continue to trigger reserve margin targets and ProbA thresholds for elevated risk. To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years. The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years, as shown in **Table 14** below.

Table 14: SERC-East ProbA Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	143	232	539
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.15	0.33
Category	Normal	Elevated	Elevated
*** Provides the 2024 ProbA Results for Comparison**			

[18] Additional details available in the report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf/

Normal-Risk Area Details

All other assessment areas (see Figure 1) are classified as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Risk Assessment** section is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2025 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that the risk assessment map will expand with more elevated- and high risk areas in the future.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, petroleum, and nuclear generators can negatively affect the resource adequacy and reliability of the BPS in the next 10 years. In the preceding **Capacity and Energy Risk Assessment**, NERC accounted for nearly 92GW of nameplate of fossil-fired and nuclear generator retirements that are anticipated through 2035. NERC's risk analysis did not include an additional 65 GW of nameplate fossil-fired generators that have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. Combined, the confirmed and announced-potential retirements over the next 10 years total over 105 GW in peak seasonal capacity, roughly 10 GW lower than the 10-year retirement projections in the *2024 LTRA* (see **Figure 6**). Projected retirements overall, both confirmed and unconfirmed, have shrunk from the prior year's LTRA as reliability needs have expanded with the continued growth in anticipated large-load interconnections. The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Growing demand and evolving planning methodologies have highlighted the potential need to keep resources, particularly non-variable resources, on-line longer than previously anticipated.

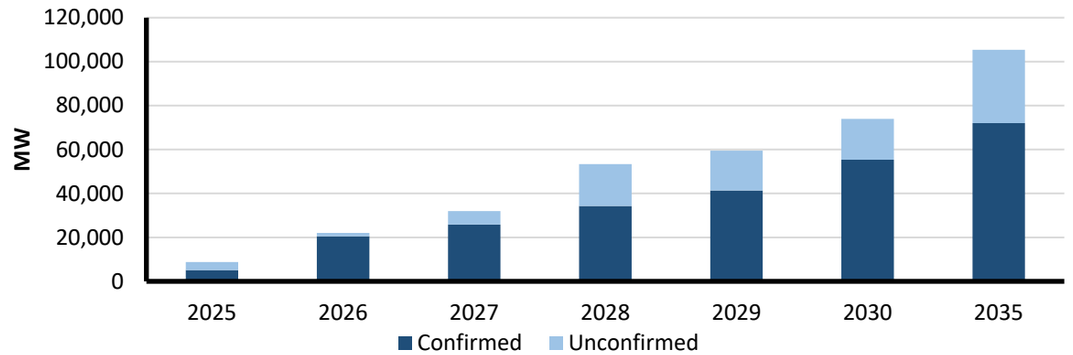


Figure 6: Projected Generation Retirement Capacity Through 2035

Figure 7 shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] MISO continues to lead the assessment areas in the amount of projected retiring capacity at roughly 35 GW.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from Additional Generator Retirements** section.

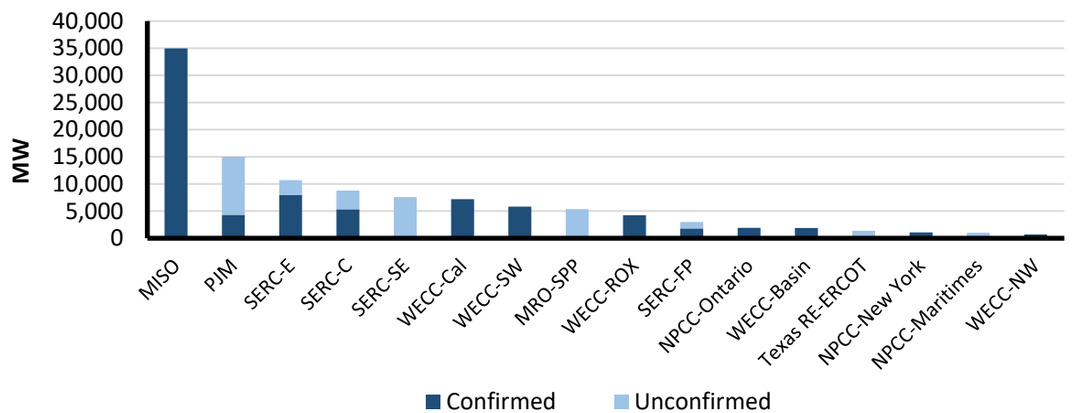


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2025 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the **Executive Summary**.

Resource Adequacy Program Attributes

Utilities, market operators, and regulators across North America are adapting their resource adequacy programs to address mounting challenges, including load growth, changing load behavior, resource mix transition, extreme weather, and evolving end-use need for electricity. NERC and industry stakeholders have recognized key resource adequacy program attributes that may become needed to address specific challenges faced by system planners and operators. **Table 15** includes five of these attributes and a brief description of how the attribute can be implemented. Assuring an adequate supply of electricity requires modernizing planning approaches. NERC encourages each assessment area to evaluate the program attributes needed to plan effectively for current and future challenges and implement those identified as essential.

Table 15: Resource Adequacy Program Attributes

Attributes	Objective	Implementation
1. Uses Energy Risk Criteria	To ensure energy adequacy in systems with VER and fuel limitations, resource planners and markets need to augment existing 1-day-in-10 load-loss criteria with additional energy risk metrics.	Establish criteria based on EUE or similar energy risk metric(s).
2. Evaluates Resource Contributions at Risk Periods	As periods of shortfall risk on the system change with changing resource and demand characteristics (e.g., risks during winter and summer, peak net demand, and shoulder seasons), methods for assigning resource contributions in resource procurement and assessments must evolve.	Adopt effective load-carrying capability or other probabilistic methods for determining resource contributions during risk periods.
3. Load Forecasting Accounts for Growth Uncertainty	Future electricity demand is being influenced by the pace of electrification, industrialization, data center development, and DER adoption. Load forecasts for adequacy assessment and resource planning need to account for new growth patterns and uncertainty.	Capture the forecast drivers needed for the area and address uncertainties.
4. Considers Effect of Extreme Scenarios on Adequacy	To reduce the unique resource adequacy risks from wide-area extreme weather events, resource adequacy programs should evaluate potential system impacts and weather scenarios to mitigate risk to the BPS.	Analysis considers low-probability energy events (e.g., drought, multi-day weather patterns) and adequacy criteria include load-loss event magnitude and duration.
5. Includes Coordinated Interregional Transfer Capability	Interregional transfer capability can provide enhanced reliability and resilience and is most effective when resource adequacy programs include coordination with neighbors.	Model transfer limits and deliverability; implement processes for seams coordination.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. See **Figure 8** for seasonal peak demand growth over the current and prior assessment periods and **Figure 9** for net energy growth. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter demand growth continues to outpace summer demand growth: The 10-year aggregated winter peak demand is forecast to rise by over 245 GW, a 65% increase from last year's 149 GW growth projection. Compound annual growth rates (CAGR) for summer and winter peak demand are the highest since NERC's tracking started in 1995. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 10.**

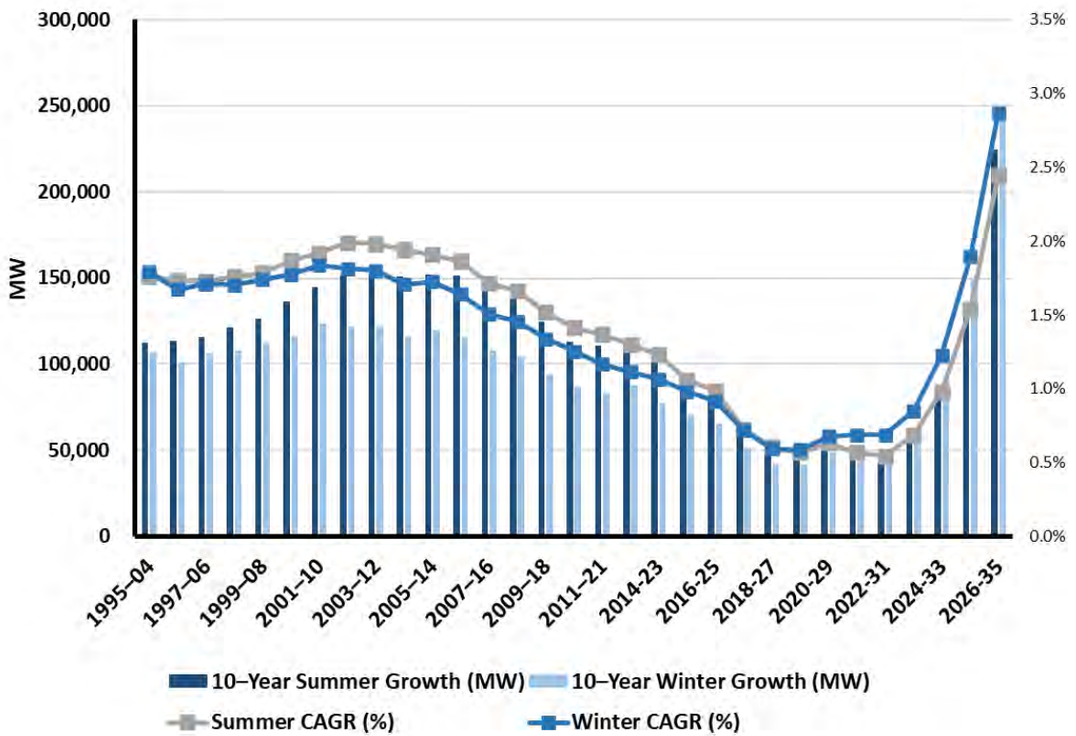


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

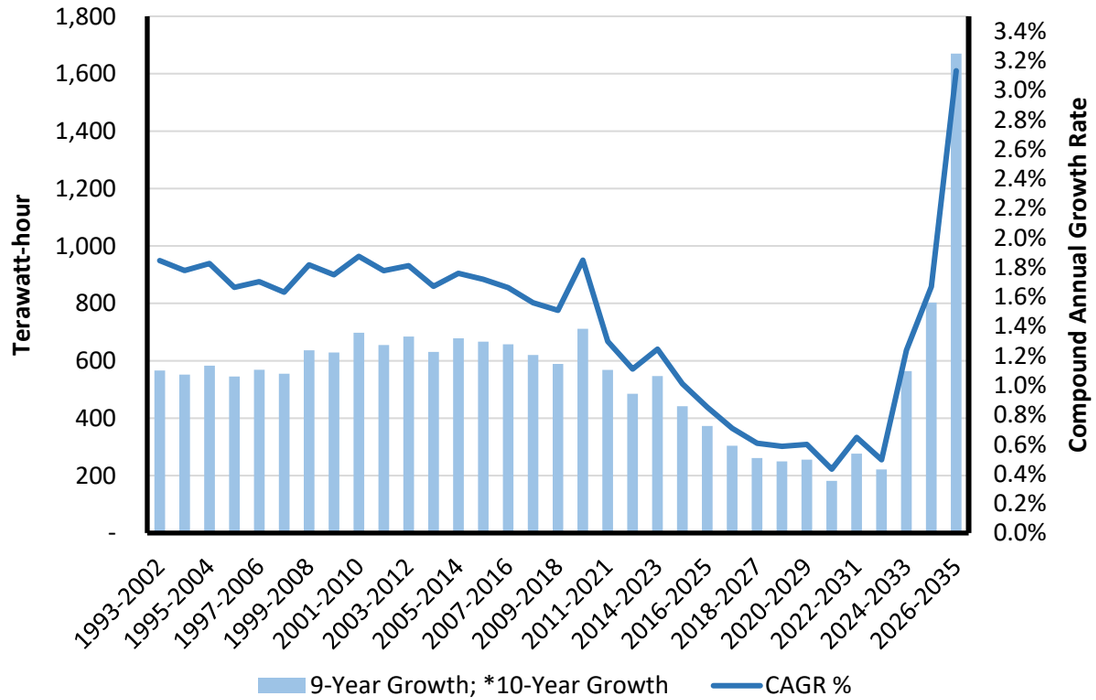


Figure 9: Net Energy for Load Growth and Rate Projections

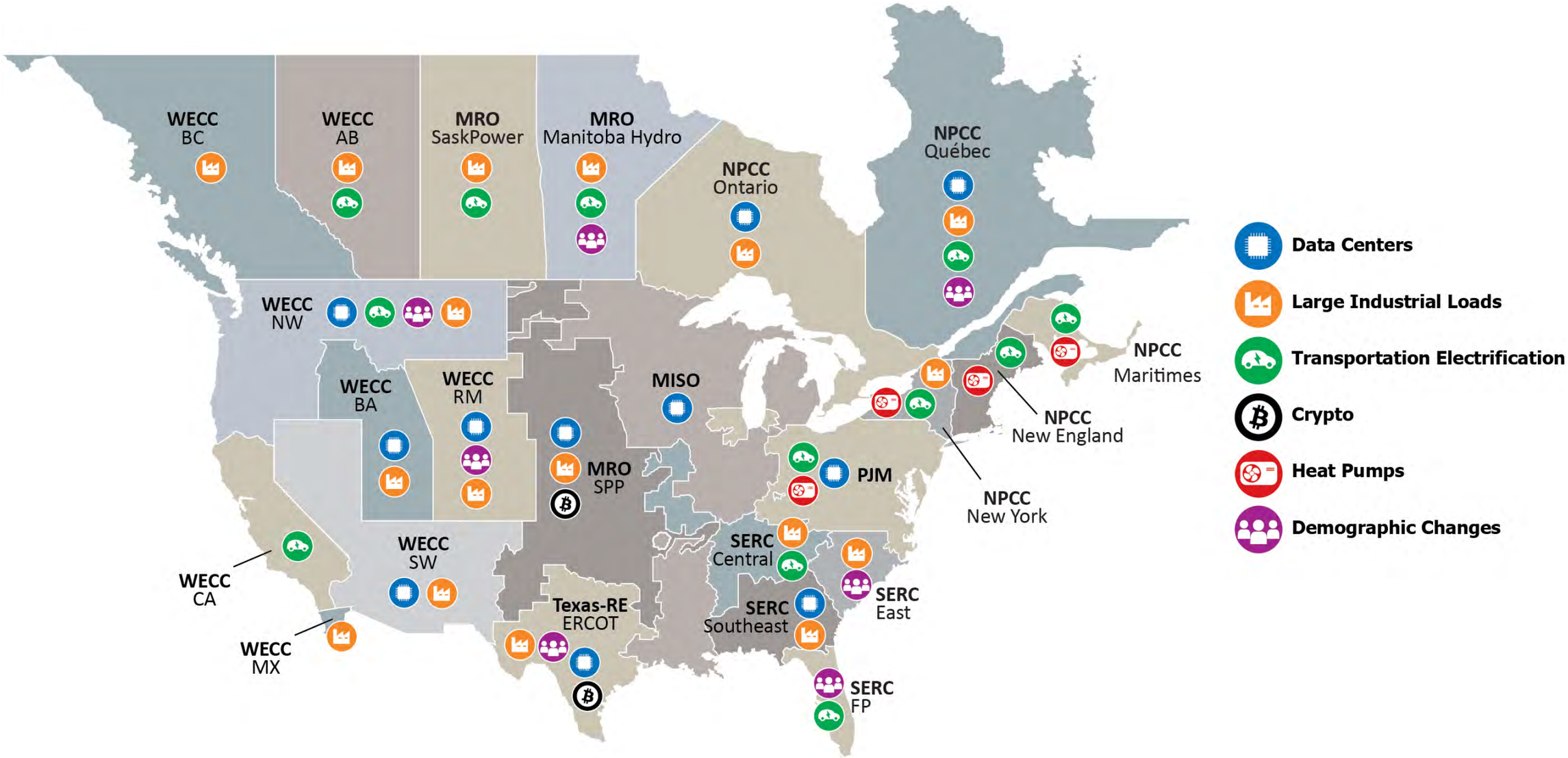


Figure 10: Primary Demand Drivers by Assessment Area

Data Centers and Large Commercial and Industrial Loads

New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years. These and other large commercial and industrial loads are connecting rapidly to the BPS. The emerging large loads present unique challenges to forecasting and planning for increased demand.

Load forecasts collected by NERC for the *2025 LTRA* reveal the massive build-out of data centers in many parts of North America. Texas, PJM, and the WECC assessment areas are reporting steep demand increases due primarily to new data centers and large loads. BAs within WECC reported that planned data centers account for an average of 10% of demand, with some BAs reporting as high as 40% of the demand forecast. See **Figure 11** and **Figure 12** for projections in ERCOT and most WECC assessment areas, respectively.

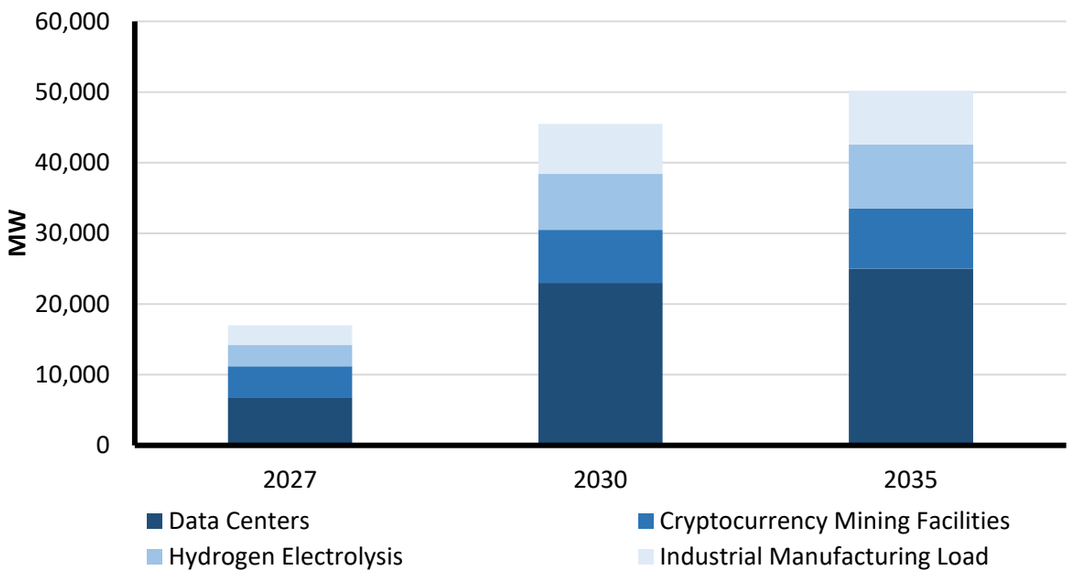


Figure 11: Large-Load Projection Breakdown in ERCOT

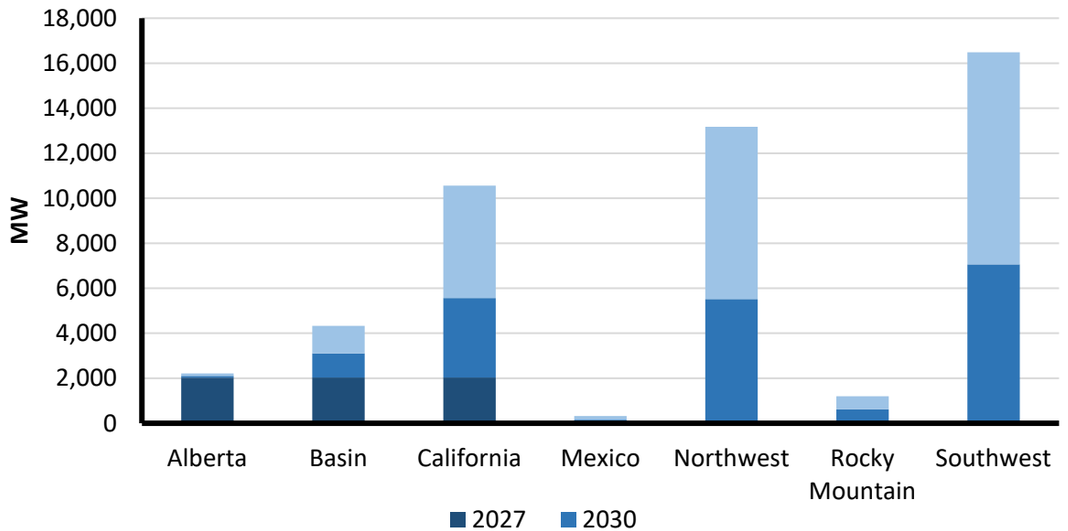


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

Demand forecasts and large load projections throughout the LTRA are based on LSE and BPS system planner forecasts. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Consequently, data center and large load growth forecasts in the LTRA are likely to be more conservative than predictions from the technology industry or from economic, research, academic, and policy organizations.

In Texas, fluctuations in recent large-load interconnections activity continue to affect both near- and long-term demand expectations. Utilities and system operators are also gaining insights from large-load development and operating behaviors and applying them to future forecasts. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. New data center demand projections in Texas are reduced by almost 50% of their original requested load level to reflect the observed consumption behavior of existing data center sites during their initial operations. ERCOT also slashes most new large loads that have yet to enter a contract for transmission service from its long-term demand forecast and adjusts

expected in-service dates to account for historical delays. Similarly, PJM is refining processes for large load forecasting starting with its 2026 load forecast.[20]

There is already evidence that large loads impact BPS reliability. For example, the Eastern and ERCOT Interconnections have observed load-reduction events[21] with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC's RSTC established a Large Loads Task Force (LLTF)[22] to better understand the reliability implications of growth in large loads and develop solutions. The LLTF published the white paper *Characteristics and Risks of Emerging Large Loads*[23] in 2025, and another white paper, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, is forthcoming.[24]

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2024 LTRA*, peak season CAGR has risen in all assessment areas except five: MRO-Manitoba Hydro's winter CAGR fell from 1.79% to 1.37%, MRO-SaskPower's winter CAGR fell from 1.32% to 0.89%, NPCC-New England's summer CAGR from 1.28% to 1.05%, NPCC-New York's summer CAGR from 0.87% to 0.84%, and SERC-East's summer CAGR fell from 1.88% to 1.17%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from summer-peaking systems to winter-peaking (or dual-season peaking) systems and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (late-2030s)
- NPCC-Ontario (2030; dual-season peaking)
- Texas RE-ERCOT (2035)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer. In Canada, WECC-Alberta has been operating as a dual-peaking system.

Demand Response

Demand-side management programs are growing for many assessments areas. DR is one form of demand-side management. It consists of mainly commercial and industrial end users that have entered into agreements with load-serving entities to curtail demand when needed by grid operators. DR can assist with reducing load during critical periods of increased demand, such as heat waves or winter storms. **Figure 13**, **Figure 14**, and **Figure 15** show the increasing projections for DR in the first year of the forecast for the past five LTRA reports in Texas RE-ERCOT, NPCC-Québec, and NPCC-New York, respectively. Other forms of demand-side management include EE and conservation programs administered by utilities. The reported contributions from DR, EE, and conservation programs reduce total electricity demand in load forecasts and provide reliability benefits that are accounted in LTRA reserve margin calculations and the ProbAs.

[20] Planned revisions to PJM's treatment of large load forecasts from PJM's Load Analysis Subcommittee: 20250613-item-03--large-load-adjustment-process-improvement-discussion.pdf

[21] "Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions," NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

[22] NERC Large Loads Task Force webpage: Large Loads Task Force (LLTF)

[23] The LLTF's *Characteristics and Risks of Emerging Large Loads* White Paper

[24] The LLTF's action plan is updated regularly and contains links to white papers, guidance, and presentations.

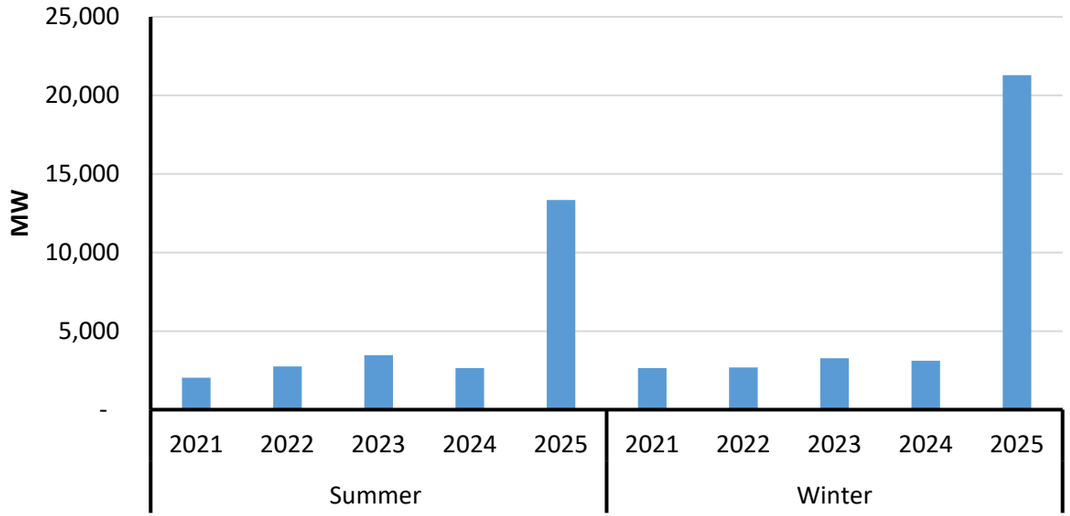


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

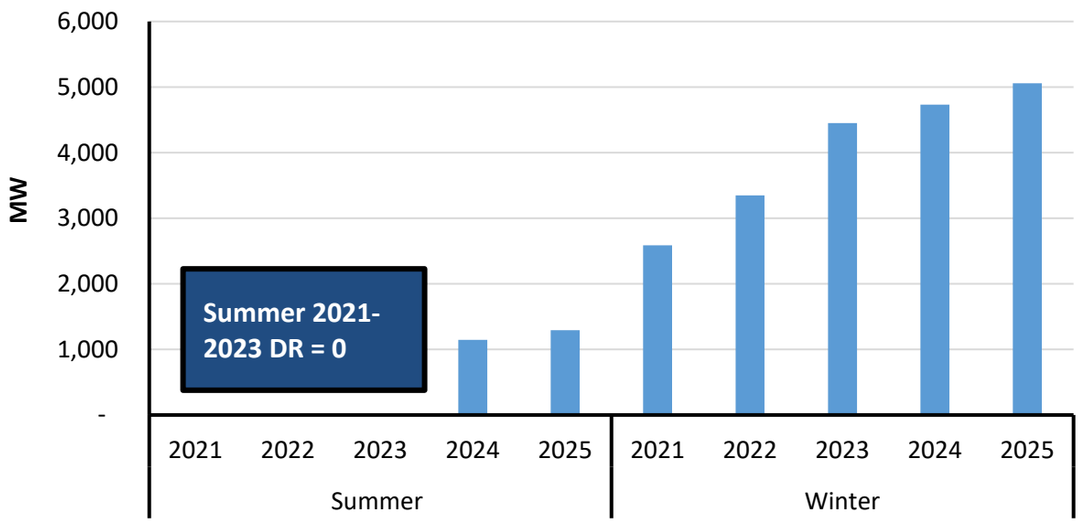


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

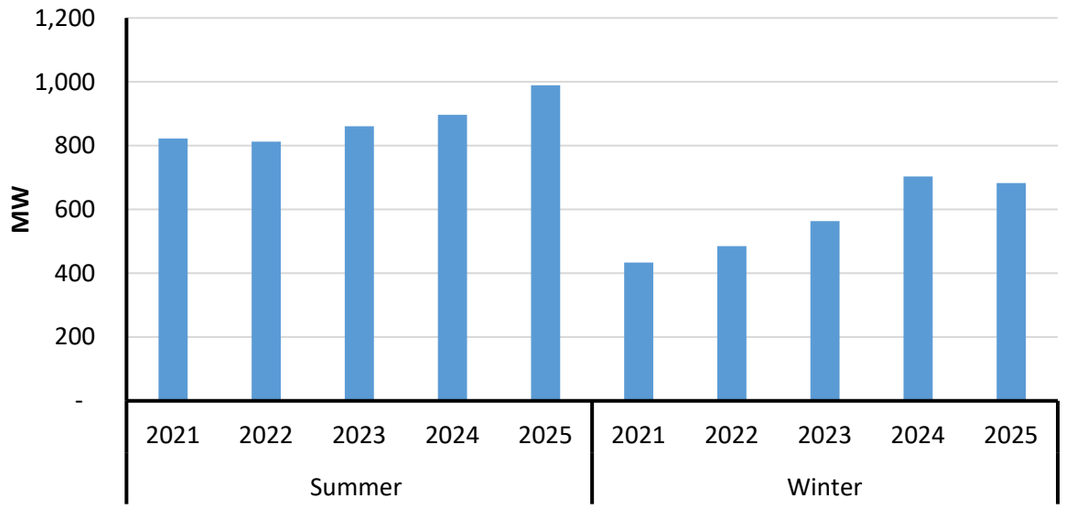


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year noticeably affected resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Resource Mix Changes

On-peak resource capacity increased approximately 6.2 GW across the interconnected North American BPS over the last year. This is down from approximately 8.3 GW of net on-peak capacity additions reported a year ago in the *2024 LTRA*. Net capacity from fossil-fueled generators continued to decline at a rapid pace over the last year with approximately 21 GW leaving the system. Continent-wide, net BPS additions of battery, wind, and solar resources totaled 23 GW over the last year (see Table 16).

Table 16: Existing BPS Resource On-Peak Capacity

Resource Type	2024 Capacity (MW)	2025 Capacity (MW)	Difference (MW)
Coal	180,402	166,799	– 13,603
Petroleum	30,987	27,931	– 3,056
Natural Gas	484,148	479,901	– 4,247
Biomass	7,381	7,181	– 200
Solar	66,293	70,723	+ 4,430
Wind	31,370	35,121	+ 3,751
Geothermal	3,881	2,932	– 949
Conventional Hydro	105,792	111,117	+ 5,325
Run-of-River Hydro	2,047	2,017	– 30
Pumped Storage	19,422	19,734	+ 312
Nuclear	105,384	105,389	+ 5
Hybrid	1,322	1,102	– 220
Other	774	830	+ 56
Battery	8,587	23,267	+ 14,680
Total	1,047,790	1,068,514	+ 6,254

Like last year, the anticipated BPS generating capacity (i.e., capacity from existing generation + expected additions – expected generator retirements) fell short of industry projections reported in the LTRA, furthering the concerns that accelerating peak demand growth is continuing to outpace the supply resources.

Figure 16 compares this year's existing and Tier 1 nameplate and on-peak capacity against the actual current capacities derived from data collected for this year's LTRA. Bars that cross the 100% line represent resources with actual additions exceeding projections from 2024, and bars that fall to the left of the 100% line represent resource types with actual additions less than projected in 2024.

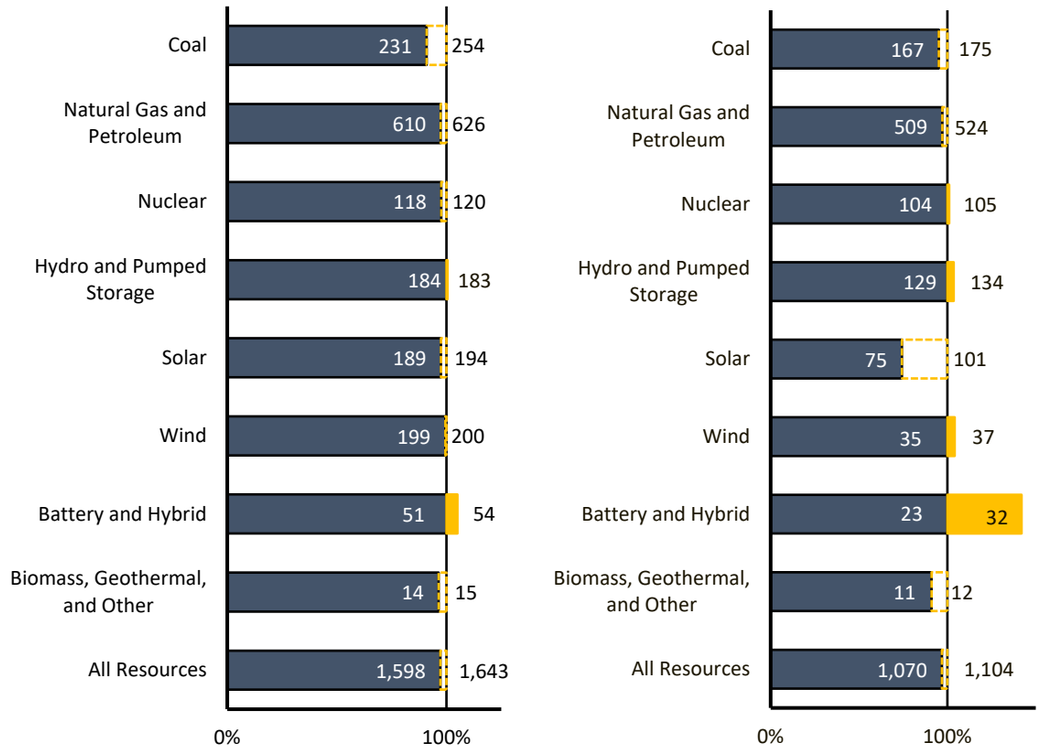


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to *2024 LTRA* Projections

Continuing the trend from last year, battery energy storage systems were added to the system faster than expected, while coal, natural gas and petroleum, and solar resources were once again over-projected. As coal capacity continued its decline because of plant retirements and age-related derating, its over-projection from last year means that it left the system faster than anticipated in 2025.

Notably, the capacity contribution of VERs, including solar, wind, battery, and some types of hydroelectric generation, to serving load at peak demand differs from the nameplate, or installed capacity. The right plot in Figure 16 above includes a complementary view to the on-peak projections using nameplate capacity to accommodate different capacity accounting methods. Both 2025 on-peak and nameplate solar was over-projected across the North American BPS last year. These over-

projections continue to support electric industry reports of construction delays and project withdrawals prior to commercial operations that prevented the expected interconnection of new resources.

Planned On-Peak Capacity Additions

New resources are added to the BPS through each area's interconnection planning process. Entities have expressed concerns that the pace of resource additions has been too slow to meet demand growth and future retirements in the existing generator fleet. **Figure 16** above highlights that industry participants are expecting peak demand growth of nearly 250 GW over the next 10 years because of accelerating demand for a variety of electricity users. Planning for such explosive growth and the uncertainty about its magnitude and timing is a complicated challenge for system planners.

Figure 17 illustrates the planned on-peak capacity additions and subtractions across the North American BPS over the next 10 years. Additions are illustrated by the positive portions of the stacked columns and include both Tier 1 and Tier 2 additions. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion (see **Demand Assumptions and Resource Categories**). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. Deratings and retirements of the existing fleet are stacked in the negative Y direction with diagonal hatching patterns.

To keep up with forecasted demand growth and generator retirements, planned resources with interconnection agreements will need to come in on time, and additional resources in development must mature through the interconnection process quickly (see **Figure 18**). The on-peak capacity of approved resource additions found in integrated resource plans (IRP) and ISO/RTO expansion plans through 2028 is able to keep pace with the aggregated peak demand forecasts of all NERC assessment areas. Beyond 2028, new approvals for resource additions are required to maintain robust growth. Furthermore, additional generation is needed to make up for capacity lost to generator retirements. Considering the generator retirements depicted in **Figure 17**, there are only approximately 60 GW of net additions planned in the most certain Tier 1 category over the next 10 years. Another 190 GW of Tier 2 or other resources (70% of Tier 2's 10-year total) would need to complete the interconnection planning process and reach commercial operations to meet the expected demand growth, illustrating the pressure on resource and system planning to rapidly add resources. DR programs, EE improvements, and transmission development to enable interregional transfers that take advantage of geographic diversity can also support growing demand.

To respond to this urgent need for new resources, independent system operators and regional transmission organizations have been developing new market structures and products to retain capacity and expedite interconnection of new generation and storage. Three such programs established by ISO/RTOs are PJM's Reliability Resource Initiative, MISO's ERAS process, and SPP's *Expedited Resource Adequacy Study*.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown only modestly since the 2024 LTRA by 7 GW (1.7%) as compared to a year-over-year growth of 44 GW last year.

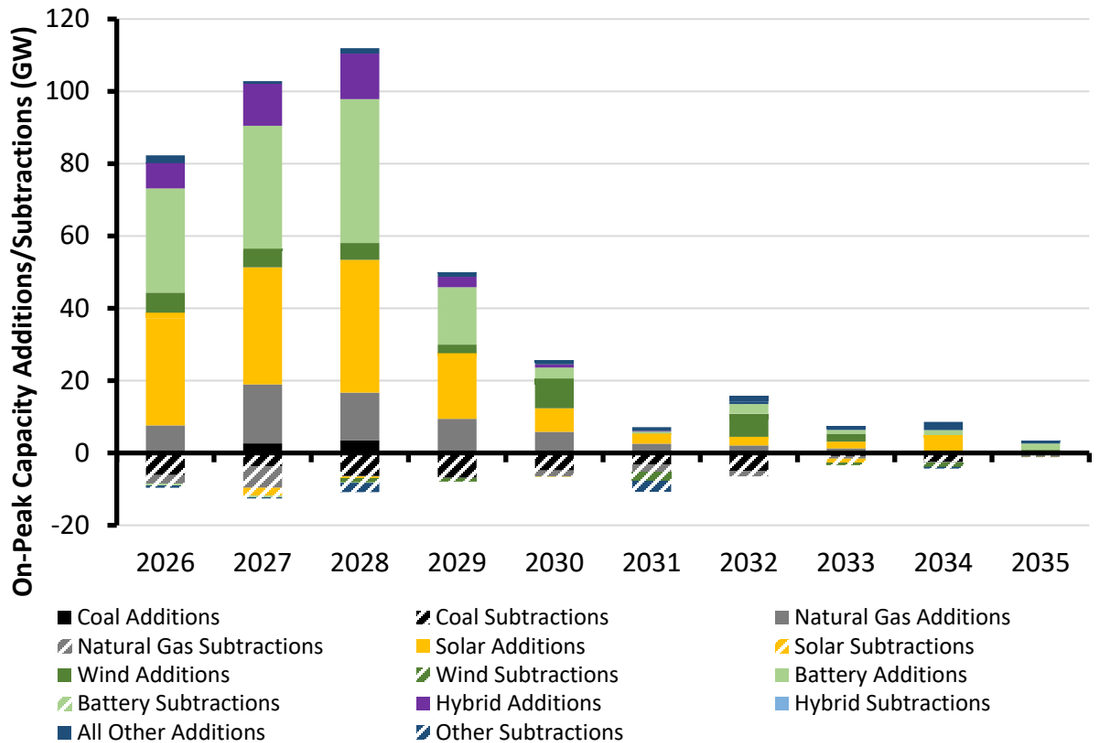


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

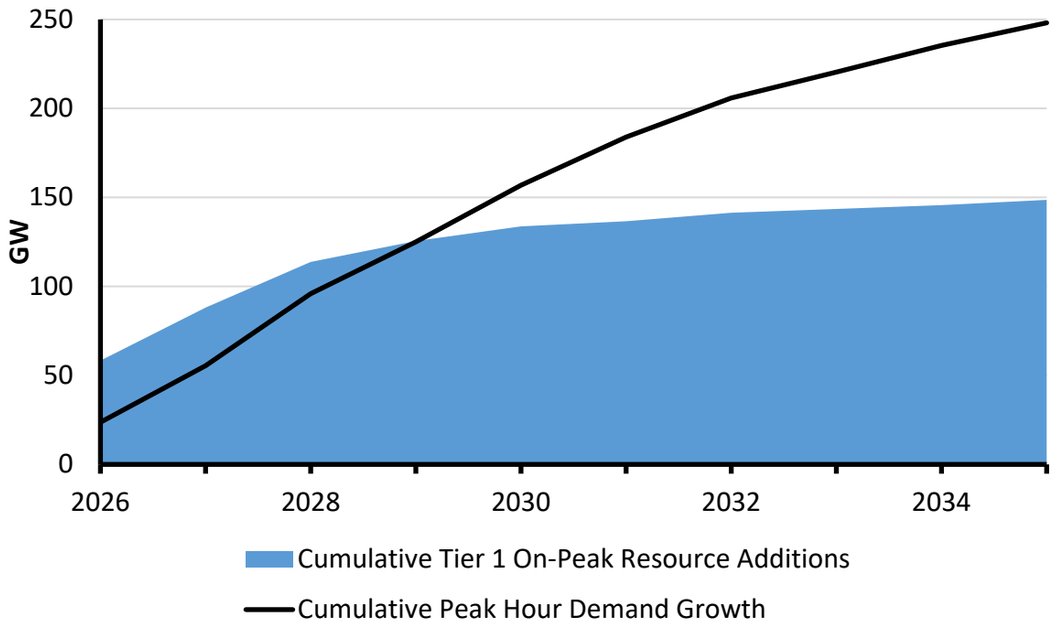


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

Increasing On-Peak Share of Variable Resources

Year-over-year increases in the fraction of on-peak capacity provided by VERs—run-of-river hydro, solar, and wind—have continued since the 2024 LTRA with VER on-peak contributions increasing from 9.5% to 10.2%. This observed trend is projected to continue through 2035 with shares of on-peak VER capacity projected to rise to between 15% and 20% depending on the completion and interconnection of Tier 1 and Tier 2 resources. **Figure 19** shows existing on-peak capacity by resource type for 2024 and 2025 along with projected on-peak capacity by resource type for 2035 with Tier 1 and Tier 2 additions. Resource types with on-peak shares less than 5% are not labeled with their contribution fraction but are stacked in the graphic.

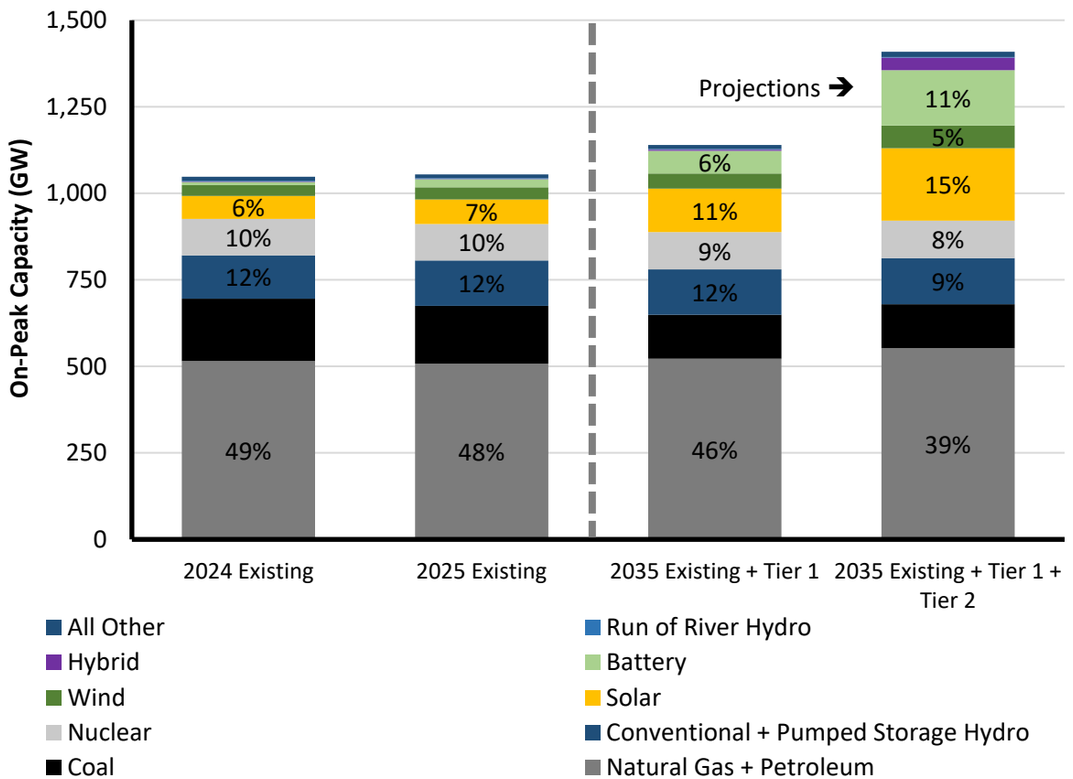


Figure 19: North America On-Peak Capacity Shares by Resource Type

Like last year, a relatively small change in total on-peak capacity was observed, but the continued trend of increasing VER share highlights that important reliability attributes continue to leave the system. Non-variable generation—including coal, petroleum, natural gas, biomass, geothermal, conventional hydro, and nuclear—as well as hybrid or storage systems can ramp up or down in response to demand. Non-variable resources can also provide other ERSs like system inertia, dynamic reactive support, and frequency response for stable grid operation. Many of the variable resources that are being added to the grid to replace non-variable resources cannot provide the same ERSs in their current configuration. This deficiency is amplified in the winter when on-peak contributions from variable resources are diminished by changing weather and environmental conditions.

System Frequency Response Analysis

Despite lower inertia from retiring synchronous generators and greater penetration of inverter-based resources, all four Interconnections expect adequate, diverse frequency response capabilities and a low risk of under-frequency load shedding (UFLS) activation. In preparing the *2025 LTRA*, NERC worked with the Regional Entities and system planners to assess the frequency response capability of the projected resource mix through 2027 on an Interconnection basis. The findings are summarized in Table 17.

Table 17: Measures of Frequency Response

Measure	What it Measures	Summary Assessment Findings
Synchronous Inertial Response (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT's use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
Rate of Change of Frequency (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. Texas RE-ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection's response to the largest credible contingency	Simulations in both the Eastern and Western Interconnection show sufficient frequency response in future planning cases.

The results of analysis for each Interconnection are in Table 18. Non-synchronous resources have increased in all Interconnections since the last LTRA frequency response analysis in 2022. Each interconnection continues to project sufficient frequency response ERSs in the near term and have low likelihood of UFLS activation during a disturbance. These results were determined by dynamic studies performed for the Eastern, Western, and Québec Interconnections and analysis of operational procedures for the Texas Interconnection.

Table 18: Summary of the Results of NERC Frequency Response Sufficiency Assessment

Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia Studied	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation
Eastern Interconnection	17.9%[25]	0	59.93 Hz	Low
Western Interconnection	42.9%[26]	0	59.65 Hz	Low
Texas Interconnection	65.7%	0	N/A	Low[27]
Québec Interconnection	37%	0	N/A	Low

Increasing Natural Gas Reliance

In 2024, natural-gas-fired power plants generated approximately 43.4% of all electricity generated in the United States, according to the U.S. Energy Information Administration, up from 43.2% in 2023. As of August 2025, natural-gas-fired power plants in the United States are on track to generate a slightly smaller share of electricity this year in comparison to last year, but accelerating energy demand through the remainder of the year and projected increases in net energy for load over the next 10 years indicate that natural-gas-fired generators will remain critical resources for BPS reliability in many areas.

Natural-gas-fired generators are especially important during the winter. Winter peak electricity demand in most areas occurs during early morning hours when unavailability of weather-dependent resources leads to a surge in natural-gas-fired generation's share of the resource mix. Severe winter weather events in 2021 and 2022 provide stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure fuel supplies during times of extreme electricity demand.

[25] EIPC Frequency Response Report

[26] 42.9% is the penetration of utility-scale non-synchronous generation. The Western Interconnection has a significant amount of DERs that are also non-synchronous. When DERs are included, the non-synchronous penetration was 54.9%.

[27] ERCOT procures responsive reserve service to protect from involuntary under frequency load shed after loss of two largest generating units at a single plant (2,805 MW). In March 2020, a new subproduct of responsive reserve service was introduced, FFR, which is triggered at 59.85 Hz within 0.25 seconds. Up to 450 MW of FFR can be procured as a part of responsive reserve service. This product is still going through implementation stages due to required changes to ERCOT systems.

Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to slightly more than 12 GW of new natural-gas-fired winter capacity if only the most certain Tier 1 resources come on-line. That number jumps to 41 GW of new natural-gas-fired winter capacity if both Tier 1 and Tier 2 resources come on-line (see **Figure 20**). Importantly, the vast majority of natural-gas-fired Tier 1 and Tier 2 additions—11 to 39 GW—are projected to come on-line in the next five years.

The timing and magnitude of natural-gas-fired generator additions remains uncertain in today's energy system planning environment. Multiple areas are conducting expedited resource assessments and interconnection process reforms with goals of adding more generator capacity to the grid over the next few years to meet rapidly accelerating electricity demands, particularly due to large-load addition. The early project submissions and selections from these programs indicate that actual natural-gas-fired additions may exceed previous industry projections in some areas. For instance, PJM Interconnection's Reliability Resource Initiative has led to the selection of approximately 8 GW of natural-gas-fired generator uprates and additions out of the nearly 17 GW of natural-gas-fired projects submitted for consideration. Round one selections for MISO's ERAS include approximately 4 GW of natural-gas-fired additions out of the 20 GW submitted to date, and SPP's *Expedited Resource Adequacy Study* includes approximately 9 GW of natural-gas-fired winter capacity additions in its interconnection queue. Most of these expedited additions that have been selected across all three programs have applied to come on-line before 2030.

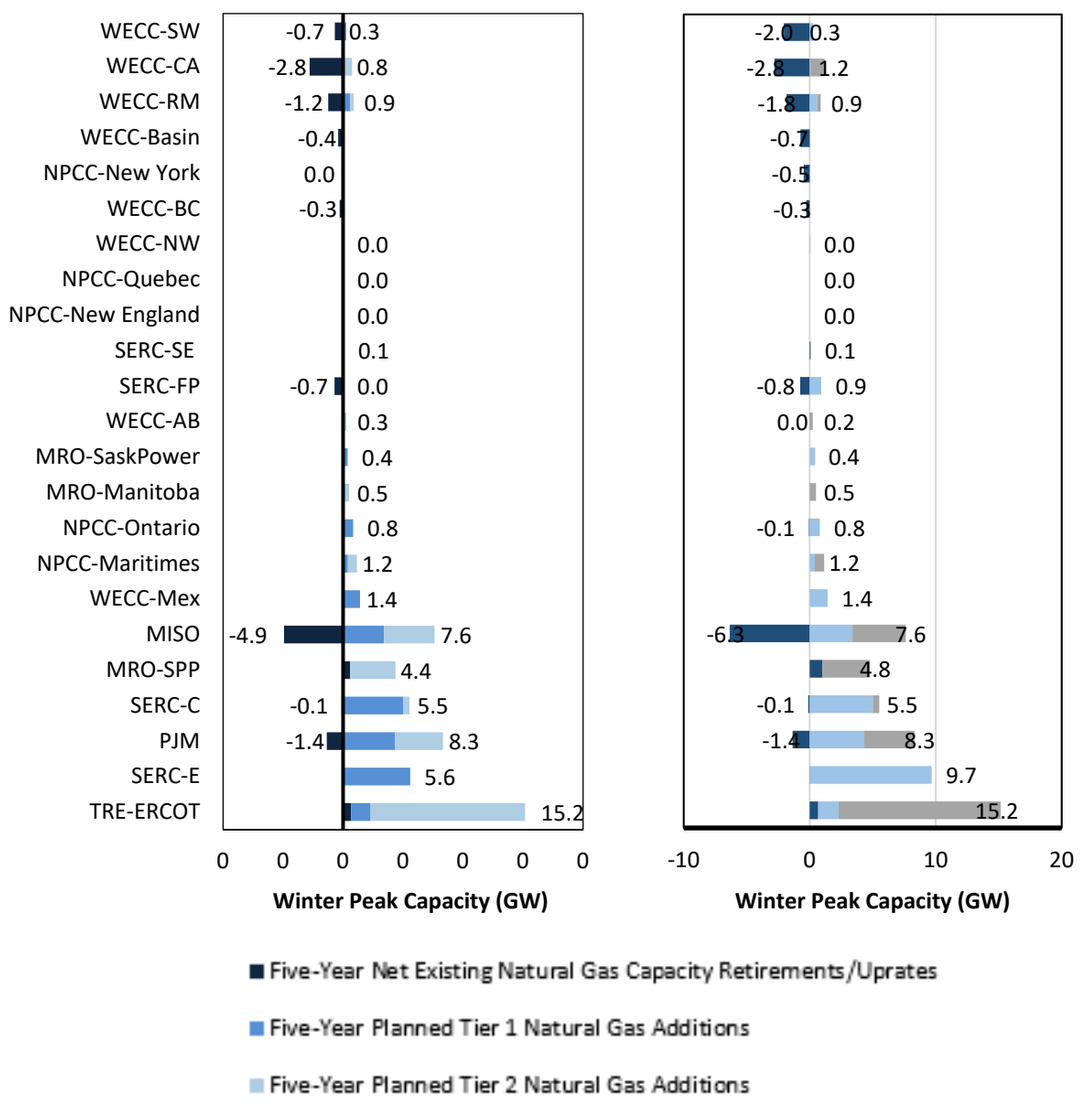


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

Natural Gas Infrastructure Development

Natural gas system planners have increasingly been coordinating with electric system planners to prepare for large additions to the natural-gas-fired power plant fleet. However, processes, regulations, and financial mechanisms that underpin capital investments and expansion of the natural gas pipeline and production system at times do not align with the variable operations of critical natural-gas-fired generators. For these reasons, among others, a significant percentage of natural-gas-fired power plants continue to rely on interruptible, or non-firm, supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas for both electricity generation and space heating can both dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability. When winter weather also impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can imperil even firm pipeline customers' supply as preparatory linepack is rapidly depleted.

There is a possibility that generators in the areas that are adding the most gas resources—MISO, MRO-SPP, PJM, SERC-C, SERC-E, and TRE-ERCOT—could secure additional firm fuel supplies from natural gas system projects planned or proposed over the next decade. **Figure 21** shows the amount of incremental natural gas pipeline capacity with in-service dates spanning the next five years. In total, S&P Global Energy projects that roughly 45 BCF/day of incremental natural gas pipeline capacity created by additional compression, expansions, pipeline repurposing, new pipelines, or reversal of flow directions will be built over the next decade. About one-third of this incremental capacity has gained regulatory approval and moved into the more formal stages of project development. Of the 15 BCF/day of regulatory approved gas pipeline capacity additions, only 5 BCF/day is planned to serve natural gas demand in the states outside of the Gulf Coast region.

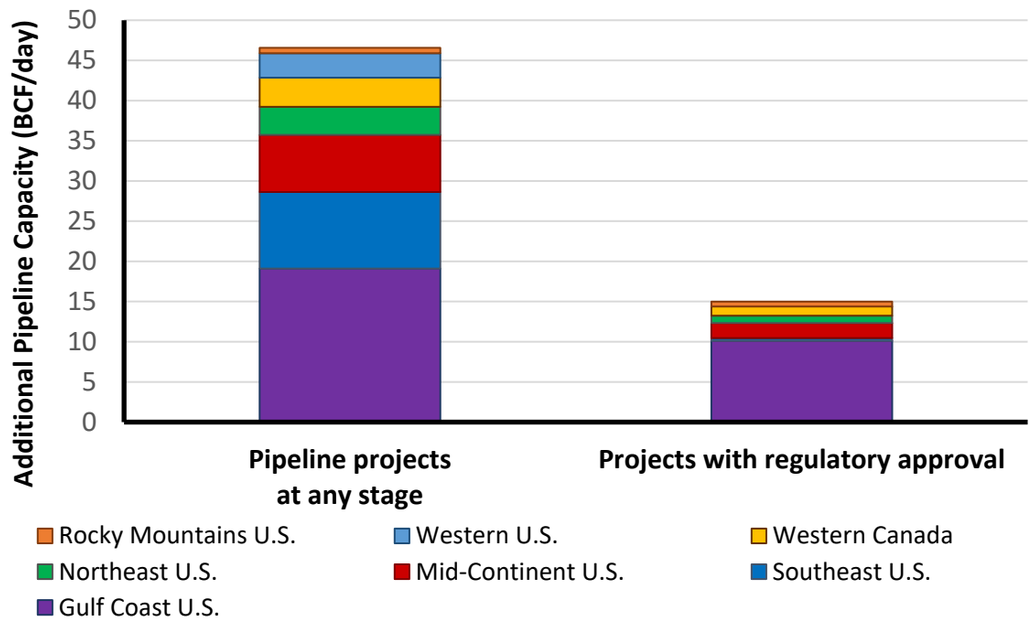


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

The nearly 40 GW of natural-gas-fired winter capacity additions in the six areas adding the most gas resources could consume as much as 6–11 BCF/day of natural gas during a peak winter day after factoring plant type, efficiency, and whether the generator designated by its grid operator as a critical on-peak resource. While enough incremental pipeline additions to support this anticipated increase in gas demand seem to be moving through the natural gas project development process in those regions (see **Figure 22**), generators will need to compete with other pipeline customers for firm supply and delivery during periods of high gas demand. The magnitude of gas pipeline capacity additions suggests that there may be promising opportunities for generators to procure firm gas pipeline and supply contracts, but regulatory approval does not assure construction or commercial operation. In addition, if firm gas contracts cannot be secured for coincident high gas and electricity demand periods, like winter, ongoing critical generator projects might need to consider backup fuel capabilities so that they can assure fuel availability.

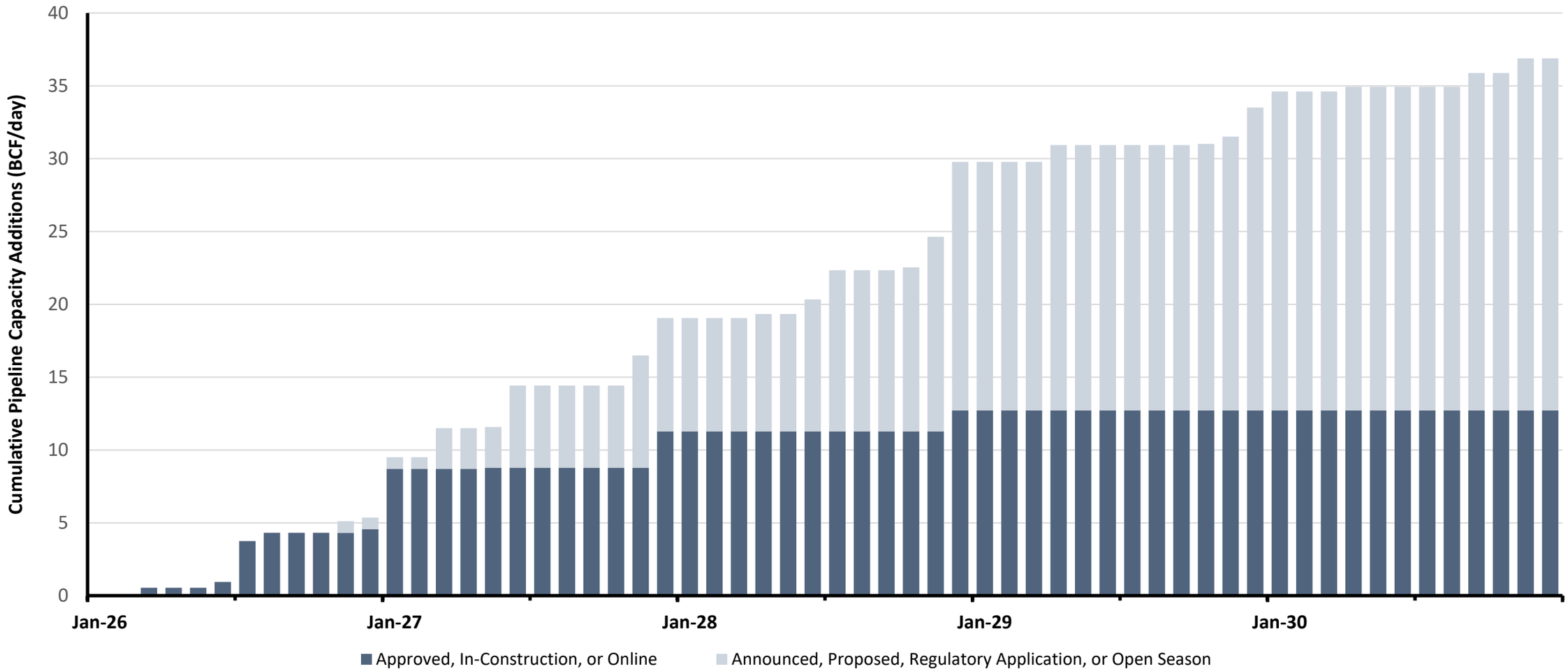


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years (see **Figure 23**) is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

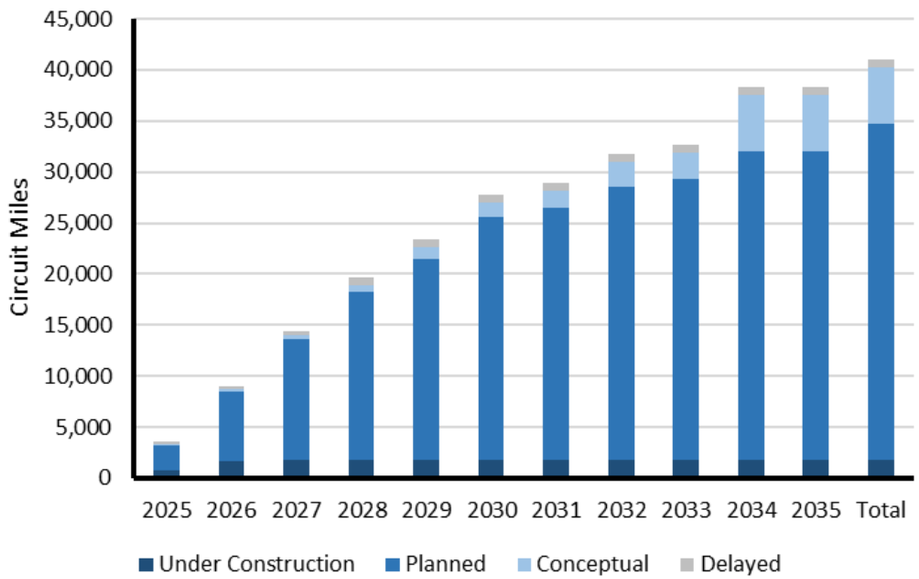


Figure 23: Future Transmission Circuit Miles >100 kV by Project Status[28]

Transmission flow patterns are changing and becoming more dynamic with resource shifts. New transmission projects are being driven by reliability, which includes efforts to replace aging infrastructure, integrate renewable generation, retire existing power plants, or meet increased demand forecasts. One such example is Hydro-Québec's plan to add significant new generating capacity by 2035, which necessitates several major EHV transmission projects. Similarly, several PCs have recently approved, or are actively contemplating, expansive EHV overlays on their systems to address a variety of needs, including ERCOT, SPP, MISO, PJM, British Columbia, and IESO. **Figure 24** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria.

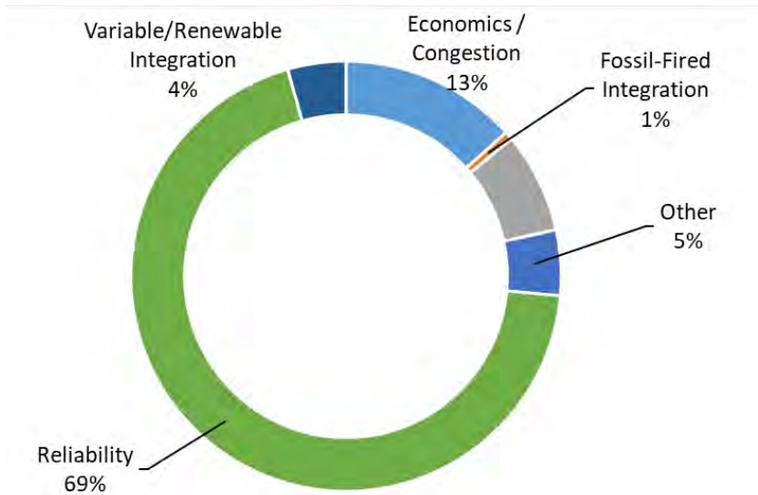


Figure 24: Future Transmission Circuit Miles by Primary Driver

There were 14,150 circuit miles (22,775 km) of reported transmission in development with an operating class greater than 400 kV (about 35% of the total miles in development). Nevertheless, intraregional transmission projects continue to greatly outnumber interregional transmission expansion. These interregional transmission projects can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[29] including scenarios identified in the ITCS. Only 38 of the 863 transmission projects in development are for tie-lines and tie-line upgrades (down from 70 in last year's LTRA), which can support transfer capability between neighboring BA areas, including high-capacity dc interconnections, such as the 1,200 MW Appalaches-Maine (NECEC) and the 1,250 MW Hertel-New York (CHPE) projects. NYISO has identified a reliability risk if the CHPE project is not completed in a timely fashion. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

[28] The column at right is the total transmission projects reported to NERC and includes projects that did not specify an expected in-service date.

[29] *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* | Federal Energy Regulatory Commission

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays as well as regulatory obstacles, such as siting and permitting. Other reasons for delays include economic impacts, planning and construction issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Interregional Transfer Capability Study (Canadian Analysis)

In the *2024 LTRA*, NERC provided a summary of the ITCS, a comprehensive study of existing and future interregional transfer capability undertaken by NERC in response to the Fiscal Responsibility Act of 2023. In addressing this legislation, NERC identified additions to transfer capability[30] for U.S. transmission planning regions (TPR) that could support energy adequacy.[31] NERC filed the completed study report with FERC on November 19, 2024.[32] Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces. The *ITCS Canadian Analysis* (Canadian Analysis) was published in April 2025.

The Canadian Analysis was the first-of-its-kind assessment of transfer capability and hourly energy margin analysis in Canada under a common set of assumptions but did not represent a transmission plan or blueprint. Transmission assessments, like the Canadian Analysis, are crucial to understanding potential options to mitigate future risks; however, alternative approaches other than transmission, such as local generation or demand-side solutions, can also mitigate future energy risks. The study results should be considered as an input into subsequent planning discussions that will consider broader objectives and the cost effectiveness of different alternatives to meet long-term needs.

Transfer Capability Analysis

The current transfer capability analysis between each pair of neighboring TPRs focused on 2024 Summer and 2024/25 Winter cases, with results shown in **Figure 25** and **Figure 26**, respectively. These transfer capabilities represent the ability of the entire network to move energy from one TPR to another TPR[33] but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

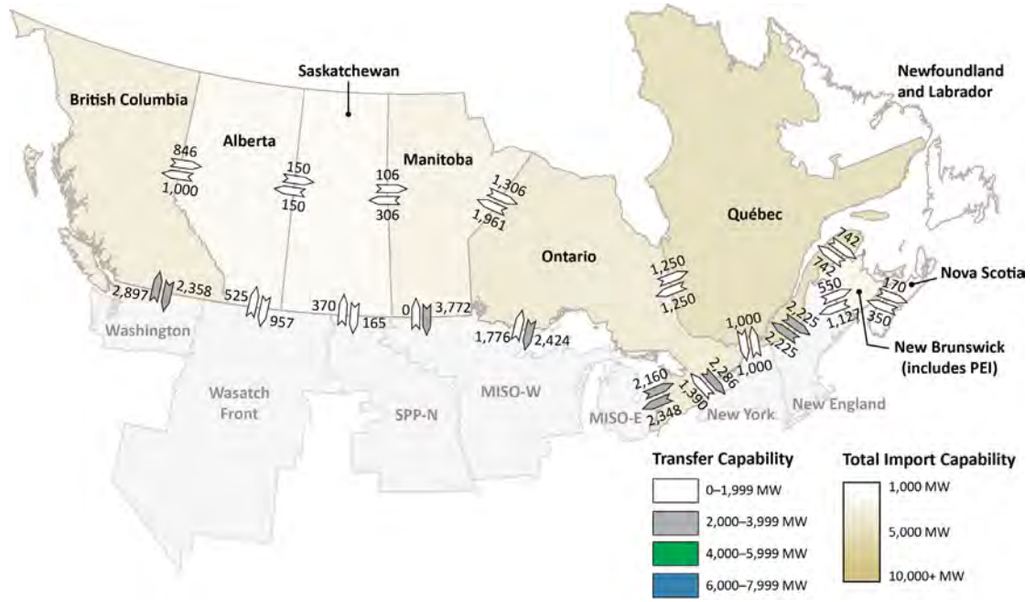


Figure 25: Transfer Capabilities (Summer)

[30] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[31] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.

[32] NERC filing of the *Interregional Transfer Capability Study*, FERC Docket AD25-4-000.

[33] Transfer capability is not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. Since this study did not follow a path-based calculation method used by many TPRs, results generally do not match individual facility ratings.

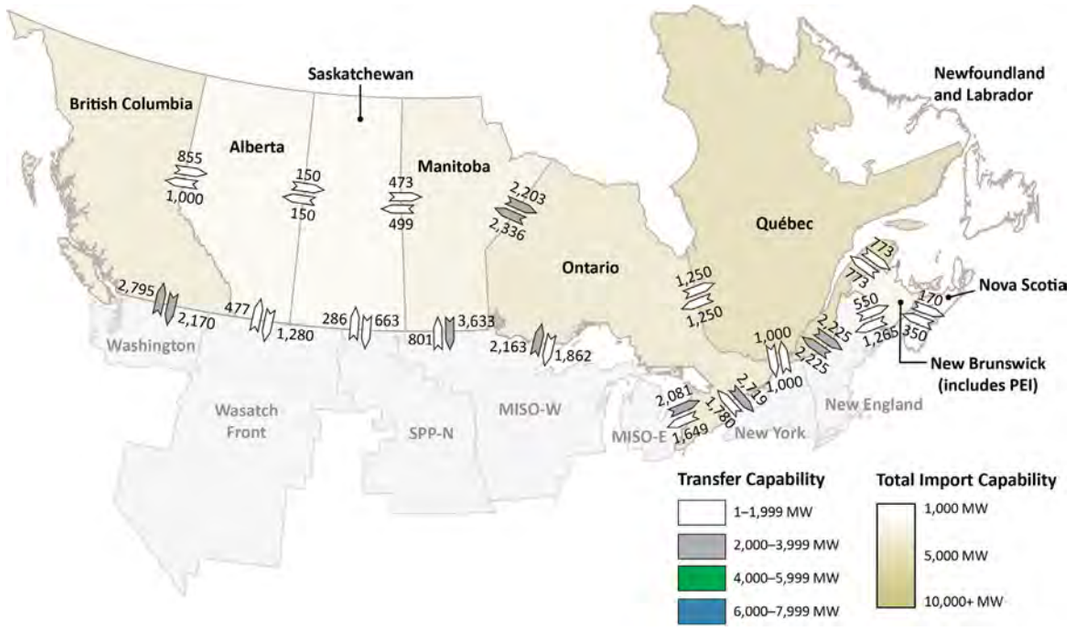


Figure 26: Transfer Capabilities (Winter)

The transfer capability results reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons.

Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

Transfer Capability Additions

The Canadian Analysis also evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again.[34] Specifically, the study applied 12 past weather years to the 2033 load and resource mix projection reported in the *2023 LTRA* using the current transfer capabilities.[35] The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. While there are several factors that Transmission Planners consider (including reliability, economics, and policy objectives) given NERC's role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

[34] This study did not incorporate climate change models.

[35] The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

Key Findings–Energy Margin Analysis (2033)

- Canadian systems, like U.S. systems, were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions.
- More recent industry forecasts reflected in *2024 LTRA* data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture future changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resource, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province's vulnerabilities, risk tolerance, economics, and policies.

Just as in the U.S. ITCS, the Canadian Analysis found potential for energy deficiency in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 GW in Québec based on *2023 LTRA* data. A sensitivity study using more recent forecasts, based on *2024 LTRA* data, generally resulted in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. The analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada. In the U.S. analysis reported last year, 35 GW of additional transfer capability was recommended across the U.S. to improve energy adequacy under extreme conditions. **Figure 27** shows the existing and potential new interfaces for Canadian TPRs where beneficial additional transfer capability is identified.

Transfer capability additions are based on 2033 resource mix and other study assumptions

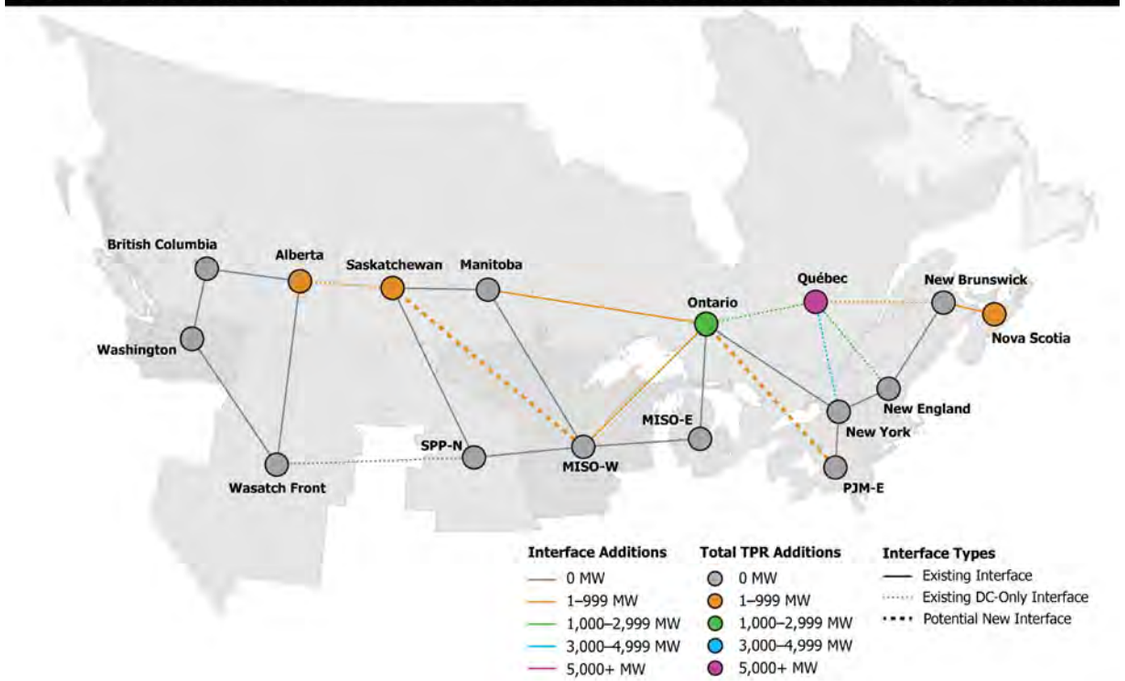
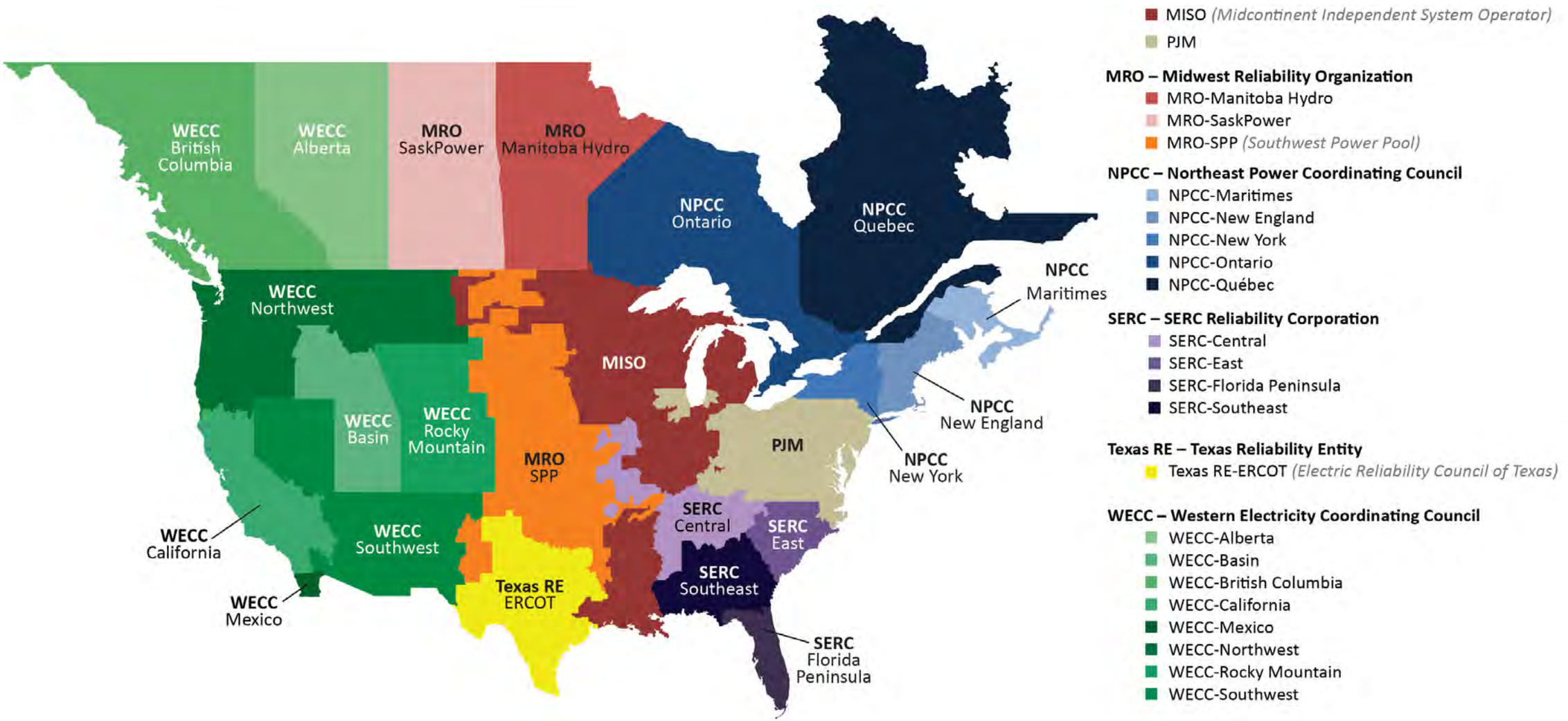


Figure 27: Transfer Capability Additions

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



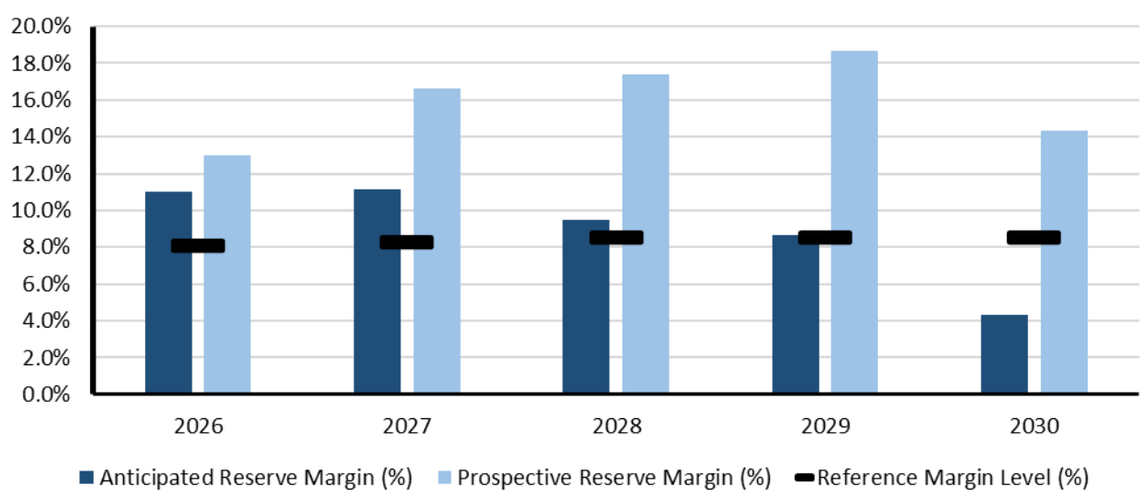


MISO

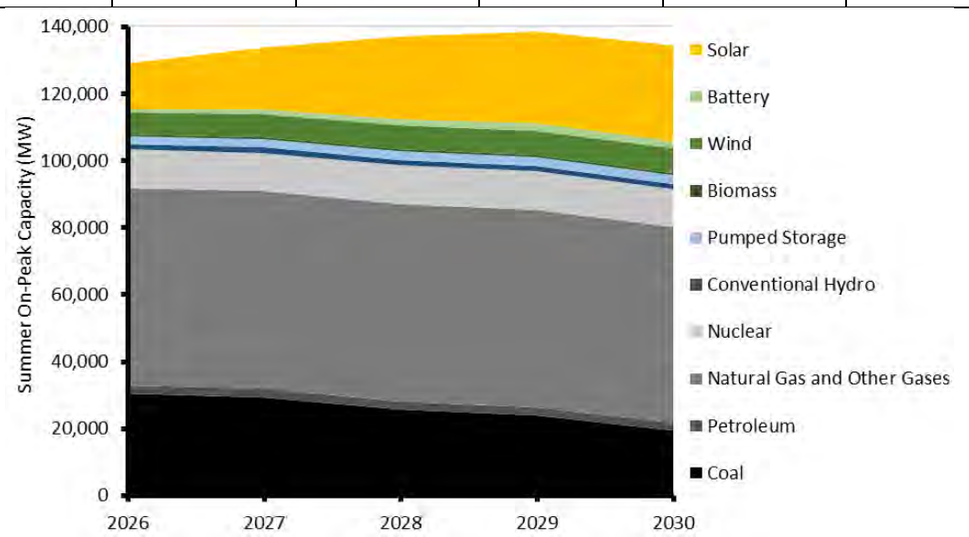
The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations and energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 79,000 miles of transmission lines and approximately 1,979 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	127,071	131,107	135,998	138,286	139,631	140,959	142,003	142,789	143,754	143,754
Demand Response	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Net Internal Demand	118,791	122,827	127,718	130,006	131,351	132,679	133,723	134,509	135,474	135,474
Additions: Tier 1	5,576	13,339	21,350	24,631	26,027	26,320	26,366	26,366	26,366	26,366
Additions: Tier 2	2,403	6,723	10,072	13,056	13,116	13,260	13,364	13,466	13,466	13,466
Additions: Tier 3	1,632	4,459	9,395	14,474	19,823	23,820	27,983	27,858	27,915	28,077
Net Firm Capacity Transfers	2,809	2,661	2,509	2,509	2,419	2,419	2,419	2,419	2,419	2,419
Existing-Certain and Net Firm Transfers	126,263	123,205	118,481	116,593	110,996	108,686	106,448	106,568	106,553	106,553
Anticipated Reserve Margin (%)	11.0%	11.2%	9.5%	8.6%	4.3%	1.8%	-0.7%	-1.2%	-1.9%	-1.9%
Prospective Reserve Margin (%)	13.0%	16.6%	17.4%	18.7%	14.3%	11.7%	9.3%	8.8%	8.1%	8.1%
Reference Margin Level (%)	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%	8.9%



Planning Reserve Margins



Existing and Tier 1 Resources

MISO Highlights

- For Summer 2026, MISO projects a prospective resource surplus ranging from 3.4 to 5.8 GW, but, if historical rates of resource additions continue, a deficit of resources beginning in Summer 2030 may be realized. The recently approved ERAS is expected to result in a considerable amount of new resource additions to the MISO system by 2029, which was not included in this year's assessment due to the timing of FERC approval. As of December 2025, around 30 GW of new capacity is being studied through the ERAS process.
- MISO forecasts that the coincident total internal demand will peak at 127.1 GW during the 2026 Summer season and will grow to 143.7 GW by 2035. The largest contributor to this demand growth is data center additions.
- MISO's accredited thermal capacity has decreased by 8.8 GW, primarily driven by reductions in accredited capacity of existing resources, and accredited non-thermal capacity has increased by 5.7 GW since last year, primarily driven by solar additions.
- In July 2025, MISO had more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that were projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity.
- Currently, MISO has surplus transfer capacity within its subregions, but transfers between subregions have been historically constrained by a transmission limitation between the two subregions. MISO members plan to invest $30 billion to install nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines to address local, regional, and interregional transmission needs.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	30,442	29,376	25,620	23,780	19,384
Petroleum	2,551	2,551	2,551	2,551	2,428
Natural Gas	58,748	58,892	58,984	59,099	58,262
Biomass	585	580	516	515	512
Solar	13,586	18,496	24,792	27,499	28,629
Wind	6,576	6,757	7,139	7,258	7,379
Conventional Hydro	1,521	1,523	1,524	1,524	1,524
Pumped Storage	2,608	2,608	2,608	2,608	2,608
Nuclear	11,571	11,571	11,571	11,571	11,571
Other	68	68	68	68	63
Battery	774	1,462	1,950	2,243	2,243
Total MW	**129,031**	**133,883**	**137,322**	**138,715**	**134,604**

MISO Assessment

MISO's guiding principles for its planning process include six key objectives: reliability and resilience; economic efficiency/lowest total electric system cost; support of federal, state, and local energy policy and member goals for their respective resource mixes; appropriate cost allocation for transfer-enabling assets; analysis of an appropriate range of system scenarios and dissemination of results to relevant decisionmakers; and coordinated planning processes among neighbors to eliminate barriers to reliable and efficient operations. See MISO's Statement of Guiding Principles for more information.

Planning Reserve Margins

Every year, MISO coordinates with its stakeholders to calculate the minimum amount of capacity above coincident peak demand required such that the LOLE equals one-day-in-10 years, or 0.1 days per year. For the MISO-wide analysis, generating units were modeled as part of their appropriate local resource zone as a subset of a larger MISO system. The MISO system was modeled with no internal transmission limitations between zones. To meet the LOLE reliability criteria, capacity is either added or removed from the MISO system within the model. The minimum amount of capacity above the MISO system coincident peak demand forecast required to meet the LOLE reliability criteria was used to establish seasonal Planning Reserve Margin (PRM) values. This minimum PRM is based on a probabilistic analysis and is expressed for each season as an unforced capacity (UCAP) requirement based on the modeled availability of resources in the MISO system. UCAP represents an adjustment from installed capacity (ICAP) that accounts for a generator's equivalent forced outage rate demand, a measure of the probability that a generating unit will not be available due to forced outages, which MISO further adjusts to exclude events outside management control.

MISO's LOLE Study for PY 2025–2026 estimated the minimum seasonal PRM values (in UCAP) as follows:

- Summer 2026: 8.1%
- Fall 2026: 14.9%
- Winter 2026-2027: 19.1%
- Spring 2027: 26.2%

The study that produced these PRM values included a probabilistic risk modeling and power flow transfer analysis to also determine zonal local reliability requirements (LRR), zonal import ability (ZIA), zonal export ability (ZEA), capacity import limits (CIL), and capacity export limits (CEL). A software program called Strategic Energy & Risk Valuation Model (SERVM) was used to calculate LOLE for the applicable planning year.

The results of the LOLE Study for PY2 5-26 serve as inputs to the MISO Planning Resource Auction (PRA). The computed PRMs are used in area adequacy assessments unless an area includes an entity that falls under a state regulatory body's purview, in which case a state-mandated PRM may be used in MISO's analysis in place of the computed PRM.

In most of the MISO footprint, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy. Every year, MISO collaborates with the Organization of MISO States (OMS) to survey its members about their plans to maintain resource adequacy in the coming years. The OMS-MISO survey provides a resource adequacy view for the MISO region over a five-year horizon based on the latest information available at the time of survey. The 2025 OMS-MISO Survey indicated that LSEs are expected to have adequate resources to meet load reserve requirements; however, various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.

For Summer 2026, MISO projects a prospective surplus ranging from 3.4 to 5.8 GW. Moving beyond the short term, if historical rates of resource additions continue in MISO as reflected in the anticipated resources projection for the NERC LTRA, a deficit of resources beginning in summer 2030 may be realized. This potential shortage is due to accelerated load growth and inadequate build rates for new resources. Interconnection of additional identified resources in Tier 2 and potential resources in Tier 3 could present an opportunity to retain a resource surplus through the entirety of the LTRA study time frame.

In anticipation of resource shortages beginning in Summer 2030, MISO has initiated the following processes and reforms:

1. Implement the interim ERAS process to facilitate the accelerated rollout of new resources to meet increased demand growth. This process has yielded nearly 30 GW of potential new capacity as of December 2025.
2. Move to a direct loss of load (DLOL) marginal accreditation model for the 2028–2029 planning year, which is intended to better reflect the true value of the next megawatt of resources during critical hours
3. Enhance resource adequacy risk assessment and communication like aligning solar representations between the PRA and LOLE model, properly represent non-firm imports between neighboring regions, and investigate the relationship between solar and battery installations and how their capacity might impact one another.
4. Reduce queue cycle times through automation

5. Establish a more robust DR and emergency resource process moving forward to ensure non-market units are being appropriately accredited.
6. Enhance allocation of resource adequacy requirements.

Energy Risk

MISO uses a seasonal PRA and conducts seasonal resource assessments to evaluate generation availability, outage rates, and forecasted load. Based on outcomes of these processes, MISO has also initiated a change to its capacity market construct, in part, to ensure energy adequacy by evaluating how classes of resources and each individual resource help serve load during periods of the year that demonstrate the most reliability risk to the MISO system.

Beyond the probabilistic energy risk assessments associated with MISO's LOLE Study for PY 25–26, MISO has also performed additional assessments for renewable integration and regional resource evolution that touch on the topic of energy risk but are not a formal part of MISO's resource adequacy and resource planning processes.

ProbA Results

The results of the ProbA simulations show normal risk for the MISO system in study year 2027 and more pronounced, elevated risk in study year 2029 wherein MISO assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and have the ability to address uncertainties associated with these three variables.

MISO initiatives like ERAS and joint collaborative efforts between MISO, its membership, regulators, and neighboring regions will be critical to ensuring resource adequacy in the coming years.

While overall installed nameplate capacity across the system is expected to increase in the coming years, system risk can be expected as the aging thermal fleet in MISO's system continues to retire and is replaced with more intermittent, less available generation. Significant demand growth, in part due to large data center loads, has been forecasted by MISO's LSEs. It is important to note that a substantial number of large-load customers continue to evaluate their options for participation in the markets, including the potential to participate as DR resources during emergency conditions. The construction delays for new resources due to supply chain and other issues, as well as the ongoing evaluation of large-load customers, contribute to continued uncertainty regarding both overall resource availability and the prospective participation of large loads as DR resources in the markets. This substantiates that MISO, its membership, and regulators must continue to monitor retirements and large-load additions and increase resource additions to ensure future resource adequacy.

The ProbA simulations for study year 2029 resulted LOLE of 2.4 days in 1 year compared to the target of 0.1 day in 1 year. The primary drivers for the expected risks in 2029 include the following:

- Load growth increases: Peak demand for winter is expected to grow considerably—approximately 9–10 GW in 2029.
- Nameplate capacity changes: To align with MISO's annual LOLE studies and proactively send the right signals, member-submitted low certainty resources from the most recent OMS-MISO Survey were assumed to be unavailable in study year and amounted to approximately 14 GW of additional unconfirmed retirements by Winter 2029.
- Summer risk shifts to later in the day: An increased reliance on solar generation as the resource mix evolves results in summer risk appearing as solar generation ramps down.
- In Winter 2029, risk is emerging in morning and twilight hours: Shifting winter risk is driven by a combination of increased reliance on solar generation, an increase in member-submitted load forecasts, elevated thermal forced outages induced by extreme cold temperatures, and a larger generation deficit than in prior years.

Base-Case Summary of Results

	2026*	2027	2029**
EUE (MWh)	0	797	31,654
NEUE (ppm)	0	1.13	42.4
LOLH (hours per Year)	0	0.23	6.61

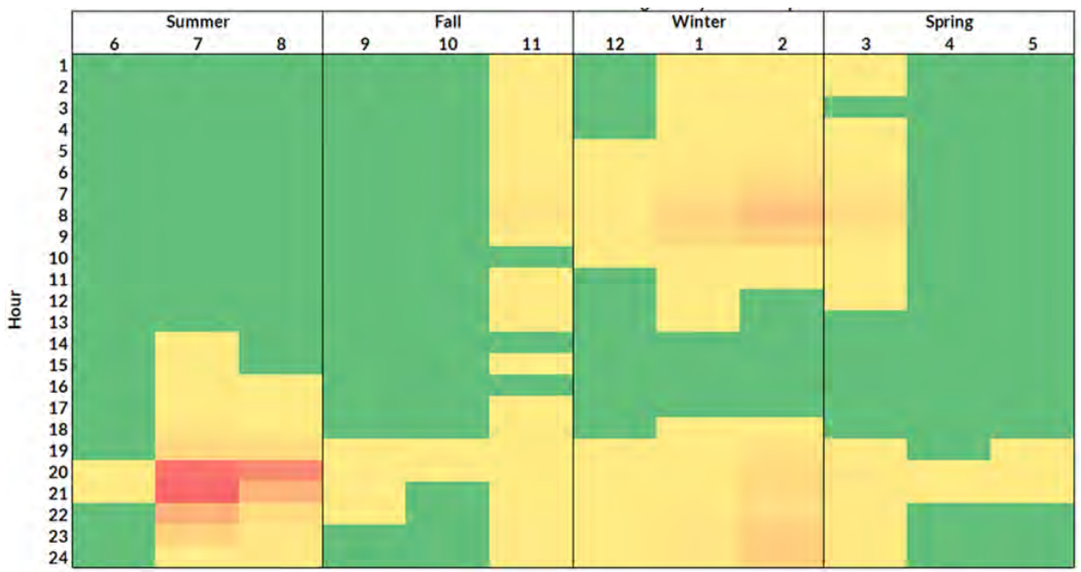
*Provides the 2024 ProbA Results for Comparison

**The 2029 ProbA study assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis.

The following EUE heat maps show the distribution of unserved energy events from the probA simulations across hours and seasons. Green cells indicate no unserved energy events, while yellow and red cells indicate increasing numbers of simulations with unserved energy.



2027-2028 ProbA Heat Map



2029-2030 ProbA Heat Map

Demand

LSEs within MISO's footprint report two sets of seasonal peak demand projections, coincident with the entire MISO system and coincident with their applicable local resource zone. LSEs also submit their non-coincident peak demand projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. Coincident peak demand forecasts are based on factors including average historical weather conditions, economic conditions, and expected demand changes. For the *2025 LTRA*, MISO used its LSE demand submissions to create non-coincident and coincident peak demand projections on a regional basis by summing the annual peak demand forecasts for the individual LSEs in the larger region of study. In MISO's normal process, the coincident peak demand forecast is used to determine each LSE's PRM requirement.

MISO forecasts the coincident total internal demand to peak at 127,071 MW during the 2026 Summer season. Since the *2024 LTRA*, MISO has increased its 10-year forecast peak demand from 132 GW to 143.7 GW. This rate of increase is expected to continue.

The largest increases in demand in the MISO footprint are related to data centers. These large load additions are projected to result in significant increases in the demand for energy in all hours and would not conform to typical residential or industrial load patterns. In total, MISO projects approximately 6 GW of data center load additions by 2027, accumulating to 14 GW by 2030, and 18 GW by 2035. MISO published a *Long-Term Load Forecast* white paper in December 2024. This white paper comes to similar conclusions around the load growth rate based upon member submissions by way of the MOD-031/FERC 714 data pathway.

Demand-Side Management

A combination of peak demand hour performance, forecasting, and baseline scenarios help MISO to determine the amount of DR capacity available during peak demand hours. DR programs continue to play a significant role in providing capacity for MISO. For the 2025/26 planning year, DR is steady around 9 GW in the summer and 8 GW in the winter and is projected to remain constant during the LTRA study horizon. MISO's latest reforms for demand-side resources focus on accrediting such resources based on their availability and performance during the highest-risk hours (in and near emergency conditions).

Distributed Energy Resources

Behind-the-meter-generation (BTMG) resources contribute about 4.4 GW of capacity across the study horizon, of which approximately 1.3 GW are distributed photovoltaics. MISO's transition to seasonal auctions highlights the variability of DERs across the four seasons, and it is working with stakeholders to derive adequate methods of aggregating, reporting and allowing DER participation in MISO markets.

Generation

Because of the size of MISO's interconnection queue, in the 2025 NERC LTRA, generation in the queue is multiplied by a reduction factor based on the study phase and likelihood of that resource coming on-line and the timing of those additions. MISO notes that the recent 2025 OMS-MISO survey used a slightly different resource addition cadence than what is reported for the LTRA that factors in both planned utility/member-specific generation addition rates and historical addition cadences. Specifically, the LTRA's existing resource capacities come directly from the 2025–2026 MISO Planning Resource Auction (PRA), based on the amount of confirmed seasonal accredited capacity. Tier 1 resources describe the expected integration rate of currently signed generator interconnection agreements (GIA) over a three-year delay ramp to represent the fact that many GIAs experience delays on their path to installation in MISO. Tier 2 resources are based on active replacement projects and Phase 3 GIAs. Tier 3 resources are based on a 15% completion rate of all non-signed GIAs with the three-year delay schedule in line with Tier 1 resources.

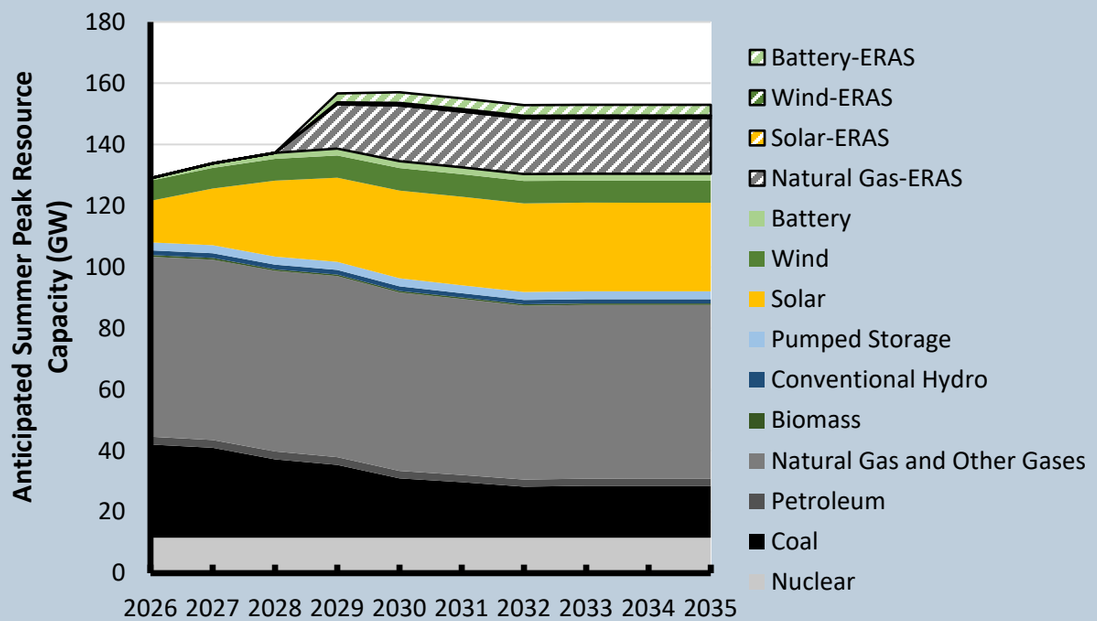
As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited capacity, driven primarily by aging existing facilities, unit suspensions, and retirements. However, suspensions and retirements in MISO have recently been followed by replacement facilities that re-utilize the interconnection service with new units. More than 75% of the units pursuing cessation in MISO are also pursuing replacement projects. Non-thermal accreditation has increased by 5.7 GW since the 2024 NERC LTRA report.

MISO's accreditation of battery resources is tied to the mandatory 4-hour energy offer window, resulting in most storage resources pursuing the ratio of 1 MW/h for 4 hours. Battery storage resources receive a 95% class-wide accreditation (relative to nameplate capacity) in the MISO PRA and NERC LTRA for their first year in operation in lieu of historical output data. Wind ELCC analyses have been performed for all seasons. Wind capacity is given the following seasonal accreditations: Summer: 20.8%; Fall: 30.7%; Winter: 29.0%; Spring: 25.3%. The effective capacity for existing solar resources is based on historical performance during typical seasonal peak hours. New solar resources get 50% accreditation relative to nameplate capacity in the summer, fall, and spring seasons and 5% in the winter season. Hydro resources accredited capacity is calculated based on historical performance during seasonal peak hours.

Energy Storage

MISO is experiencing increased interest by members for battery energy storage, with more than 500 MW currently on-line, and queue projects identifying more than 100 GW of battery or hybrid fuel type projects. MISO's anticipated installations include an addition of more than 2.4 GW by Summer 2030 and a prospective battery fleet of nearly 7 GW by 2035. The primary expected usage for batteries is for reliability, providing significant capacity capability with the variable nature of MISO's growing solar and wind fleet. MISO performs risk modeling with advanced storage representations to ensure that battery capacity is characterized appropriately.

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 the ERAS program 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* and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity

Energy Transfers
In the PRA, MISO accredits several power purchase agreements known as diversity contracts between Manitoba Hydro and MISO internal generation owners, wherein energy flows from Manitoba to the MISO system in the summer when Manitoba has excess hydro power vice-versa in the winter. Currently, MISO has surplus capacity in both the MISO North/Central and MISO South subregions, but imports and exports between them have been historically constrained by a transmission limitation.

A key input to MISO's probabilistic risk modeling that determines the system-wide seasonal PRM values is how much non-firm energy support MISO can reasonably expect from neighboring external areas. Every year, MISO performs an analysis of recent year trends in seasonal non-firm energy support to develop a range for each season that the probabilistic model will randomly draw from mid-simulation. Additionally, MISO found this year that there was not a significant difference in the amount of non-firm energy support MISO received from its neighbors during hours and days with tight operating margins when compared to normal operating conditions.

Transmission
MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure system reliability. Many factors are considered during MISO's transmission expansion planning process, including urgency of need, suitability of alternatives to address identified issues, cost effectiveness, performance of alternatives, development time frame, right-of-way or substation impacts, expandability, and operational flexibility. To learn more about MISO's transmission expansion plan, see information and reports posted on MISO's MTEP page.

MISO has 488 transmission projects totaling $30 billion planned across MTEP24, its Long Range Transmission Planning (LRTP) Tranche 2.1, and the SPP-MISO Joint Targeted Interconnection Queue (JTIQ). In total, these three programs include nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines in their project portfolios. These projects aim to address local, regional, and interregional needs across the area's large geographic footprint by enabling reliability in response to accelerating load growth. In fact, most of the demand increases reported by LSEs in the MISO footprint can be tracked to transmission projects either in the Expedited Project Review (EPR) or normal MTEP project pathway. Specifically, MISO's Tranche 2.1 Portfolio seeks to establish a transmission system backbone for the whole MISO system, and the JTIQ portfolio is being undertaken with the potential to unlock approximately 28 GW of generator interconnections, eliminating barriers to new capacity at the SPP-MISO seam.

As of December 1, 2025, MISO identified 63 projects comprising 12.8 GW of additional load through the EPR process.

Reliability Issues
Load growth and additions are increasing. A spike in large, single-site load additions from manufacturing resurgence and incremental load growth from electric vehicles and other electrification trends pose new challenges for the grid. Continued high numbers of MTEP projects submitted through the expedited project review request, which are urgent projects that cannot wait for the next full MTEP cycle to proceed, are evidence of this faster paced load growth and additions.

Maintaining resource capacity margins will require accelerated resource additions to outpace retirements and the forecasted load growth. Recent reforms have helped to reduce the volume of requests and to process them more efficiently. As of December 1st, 2025, MISO has 1,127 Active interconnection queue projects that total 215 GW of nameplate capacity. This is in addition to the 444 projects and 70 GW of signed GIAs.

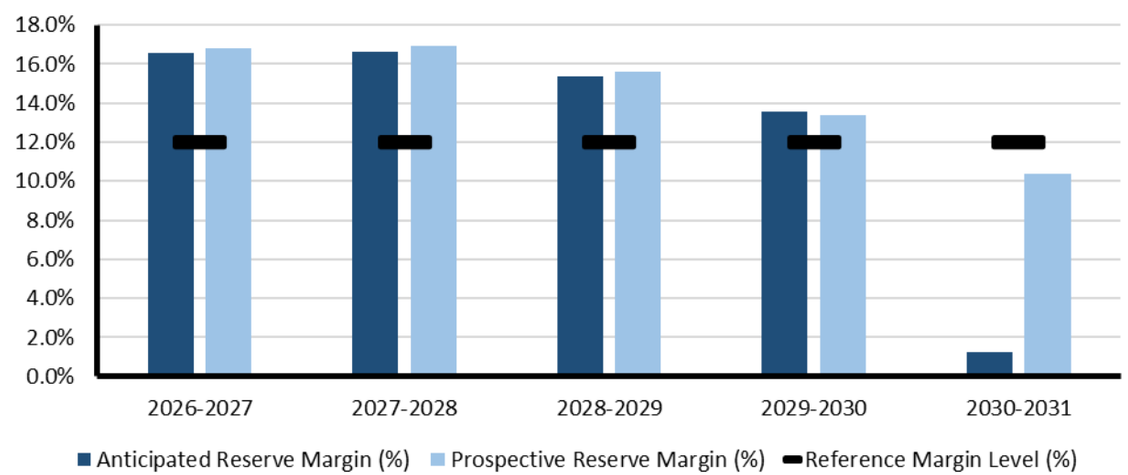


MRO-Manitoba Hydro

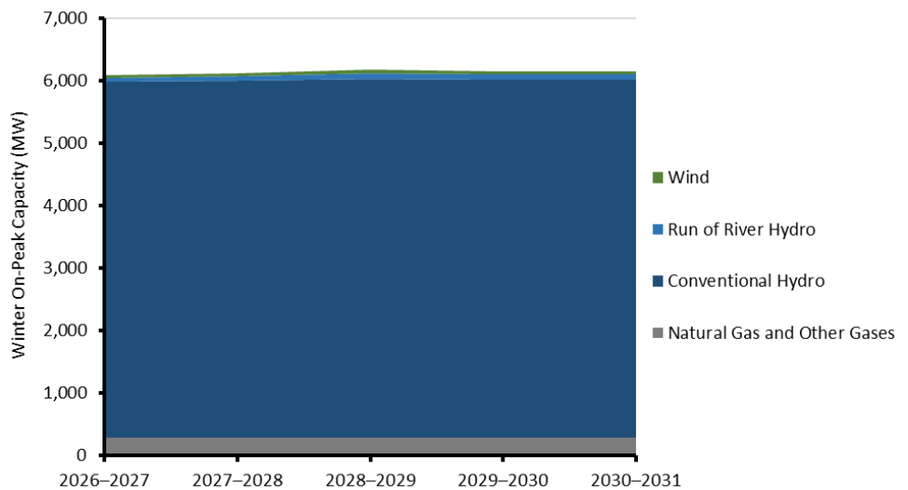
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own PC and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Additions: Tier 1	36	50	63	63	63	63	63	63	63	63
Additions: Tier 2	0	0	0	0	500	500	500	500	500	500
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-93	-167	-172	-565	-565	-565	-565	-565	-315
Existing-Certain and Net Firm Transfers	5,794	5,831	5,799	5,770	5,377	5,377	5,377	5,377	5,377	5,627
Anticipated Reserve Margin (%)	16.6%	16.7%	15.4%	13.6%	1.2%	0.5%	-0.1%	-1.2%	-2.5%	0.6%
Prospective Reserve Margin (%)	16.8%	16.9%	15.6%	13.4%	10.4%	9.6%	8.9%	7.7%	6.3%	9.3%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-Manitoba Hydro Highlights

- Manitoba projects a shortfall in anticipated resources starting in the winter of 2030–2031.
- The demand is projected to grow over 13% through the assessment period.
- The Province of Manitoba paused cryptocurrency interconnection requests until April 2026 to prepare a long-term solution to limit reliability impacts to the system.[36]

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Natural Gas	278	278	278	278	278
Wind	52	52	52	52	52
Conventional Hydro	5,705	5,723	5,758	5,735	5,735
Run of River Hydro	59	71	90	90	90
Total MW	**6,094**	**6,124**	**6,179**	**6,155**	**6,155**

[36] Province directs Manitoba Hydro to continue pause on new cryptocurrency connections

MRO-Manitoba Hydro Assessment

Planning Reserve Margins
The ARM for the summer season does not fall below the RML of 12% during the 10-year assessment period. The ARM for the winter season falls below the RML of 12% beginning in Winter 2030–2031 due to a combination load growth and reduced resources due to an ending of winter capacity import contracts ("diversity capacity") in 2030, as well as an assumed reduction of the Curtailable Rate load management program.

Demand
Manitoba Hydro is anticipating load growth of 1.5% (net of demand side management) over the assessment period. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management
Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five-minutes notice. The program is intended for peak load management. In addition, one product of the Curtailable Rate Program provides 50 MW of contingency reserves, also on five-minutes notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Manitoba Hydro is in the process of developing a new industrial rate pilot, with the combined goal of reducing winter peak and providing additional rate options for customers that both assist customer profitability and help keep costs low for all Manitobans. The rate pilot is being developed to leverage existing technology and programming with the intent of introducing the program on a pilot basis.

Manitoba Hydro, in collaboration with Efficiency Manitoba, is looking to develop a DR pilot program aimed initially at targeting smart thermostats with the focus on reducing Manitoba's winter peak. The pilot program is targeting to launch for the winter of 2025.

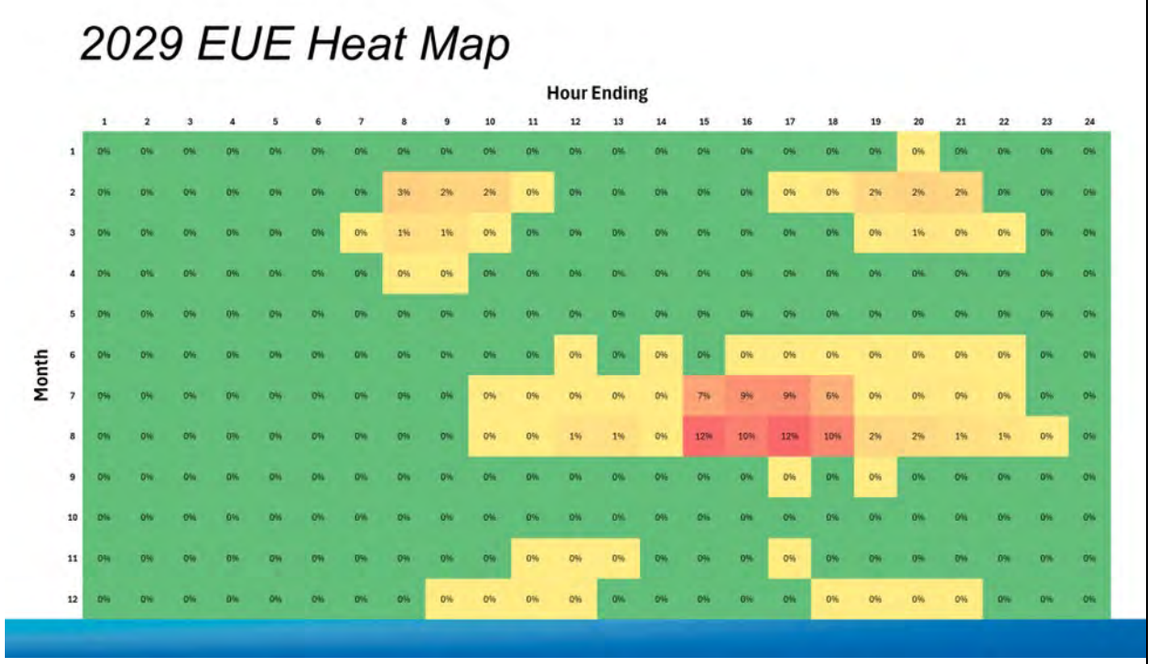
Energy Risk
As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

Probabilistic Assessment (ProbA)
Every year, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2024. The 2024 probabilistic assessment was supportive of a 12% PRM for the Manitoba system being sufficient to provide an LOLE of less than 0.1 days per year under the study assumptions. Results of the 2025 ProbA prepared for the LTRA are as follows.

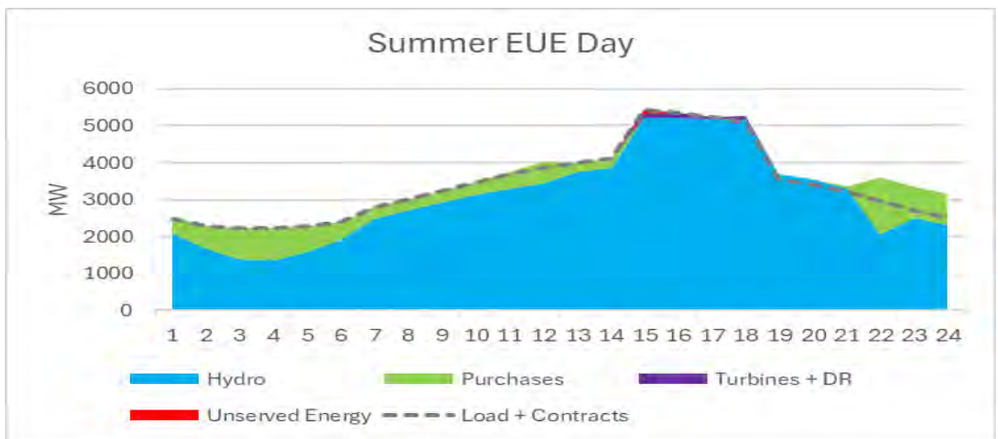
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	4	3	6
NEUE (ppm)	0.17	0.12	0.23
LOLH (hours per Year)	0.05	0.03	0.06
* Provides the 2024 ProbA Results for Comparison			

There were no appreciable Manitoba loss-of-load events seen in winter or in the summer for 37 of the 44 weather/ flow years studied. Manitoba loss-of-load events that were seen in summer occurred during the lowest flow years with upwards of 80% of the risk of loss of load occurring in the two worst flow years (1988 and 2003) of the 44 years studied. The Manitoba loss-of-load events that were seen in summer were driven by very low hydro flow conditions combined with both very high summer loads in Manitoba and very high summer loads on the MISO system.

The annual EUE heat map for 2029 is provided below.



A sample summer EUE day with very high loads on the Manitoba and MISO systems during extreme drought is shown in the illustration below. For much of the day, Manitoba is a net importer of power.



Distributed Energy Resources

There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DERs may be dependent on solar PV subsidies and/or incentives.

Generation

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. A Tier 1 project to replace eight older and smaller hydro units is in progress for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation.

On February 25, 2025, Manitoba Hydro filed with its regulator the preliminary estimate for a 500 MW gas capacity resource entering service in 2030. While not yet approved, this proposed plant was included as Tier 2 capacity resource. Manitoba is not currently experiencing the large additions of wind and solar resources seen in other regions, and hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated over the next five years. Manitoba Hydro is working on an Integrated Resource Plan that will support future investment decisions. The Government of Canada is further regulating carbon dioxide emissions from the electric generation sector, finalizing the Clean Electricity Regulations in December 2024. These regulations begin to restrict fossil fuel generation in 2035 and direct Canadian electric generation to achieve net-zero greenhouse gas emissions by 2050. Manitoba Hydro does not anticipate that meeting the Clean Electricity will have a negative impact on system reliability or modify the operation of Manitoba's electricity system. The Province of Manitoba provided energy policy direction with the publication of the Affordable Energy Plan in September 2024. Energy conservation, wind generation, and dispatchable back-up generation, such as natural gas combustion turbines, form the basis of the plan. Manitoba Hydro's forthcoming 2025 Integrated Resource Plan will be consistent with the policy direction.

Energy Storage

Additions of battery energy storage system (BESS) resources in the next 10 years are not anticipated at this time. The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources on-line are hydro generation resources, which therefore serve most operational, reliability, and economic functions. In the longer term, there may be a role for energy storage resources in Manitoba in areas that may become transmission constrained. Preliminary long-term studies of a modest amount of energy storage resources have not identified

operational challenges and have not required modification to planning assumptions since the 2024 LTRA.

Energy Transfers

The Manitoba Hydro system is winter-peaking and is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which as a whole is summer-peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. In the unlikely event of such a situation, Manitoba Hydro would implement plans developed in accordance with emergency operating procedures for capacity and energy emergencies, including calling on emergency energy from Adjacent Balancing Authority Coordination Agreements, if available. Transmission planning studies consider maximum firm winter import and N-1 and N-2 contingencies. The completion of the Manitoba–Minnesota 500 kV transmission line on June 1, 2020, increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies. The 500 kV line is equipped with single pole trip and reclose capability, which results in only one phase being out for one second during common single-phase faults.

The expiration of existing winter capacity import contracts ("diversity capacity") in 2030 is contributing to overall lower firm resources from winter 2030–2031 through the remainder of the assessment period.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue, which is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end-of-life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

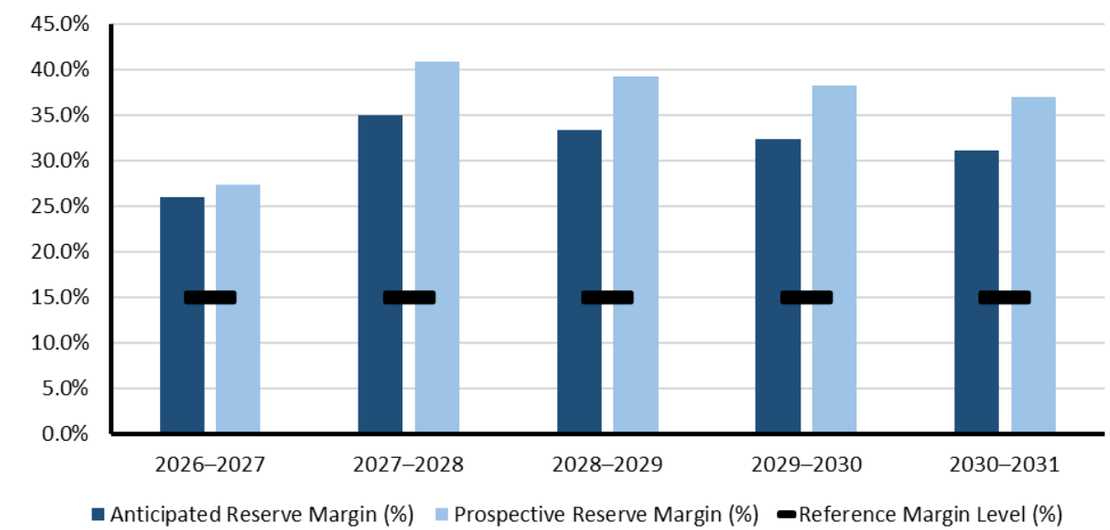


MRO-SaskPower

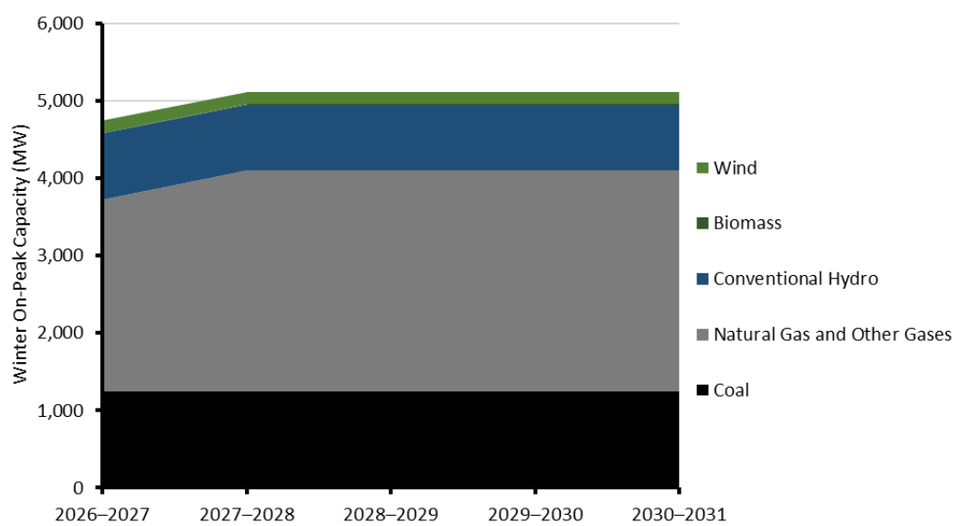
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator 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 Bulk Electric System and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	4,040	4,112	4,148	4,180	4,205	4,230	4,278	4,314	4,347	4,375
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,968	4,040	4,076	4,108	4,133	4,158	4,206	4,242	4,275	4,303
Additions: Tier 1	90	460	460	460	460	460	460	460	460	460
Additions: Tier 2	55	241	241	241	241	241	241	241	241	241
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,907	4,992	4,976	4,976	4,961	4,962	4,900	4,962	4,976	4,892
Anticipated Reserve Margin (%)	25.9%	35.0%	33.4%	32.3%	31.2%	30.4%	27.4%	27.8%	27.2%	24.4%
Prospective Reserve Margin (%)	27.3%	40.9%	39.3%	38.2%	37.0%	35.5%	32.5%	32.8%	32.1%	29.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SaskPower Highlights

- Over the next 10 years, MRO-SaskPower's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year. SaskPower's recent probabilistic studies concluded that the largest contribution to EUE occurs during peak hours because of planned outages. Rescheduling maintenance can help avoid these issues.
- Saskatchewan's average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period. Large industrial loads are the primary driver for both growth and uncertainty in SaskPower's forecast.
- SaskPower is projected to increase its wind and solar capacity to 1,550 MW in the next three years. Natural-gas-fired generation is being added to the system to offset VERs with plans to add 525 MW nameplate of new gas-fired generation—460 MW of Tier 1 and 65 MW of Tier 2—over the next 10 years. Life extensions and repowers for coal units are in process as directed by the Saskatchewan government. SaskPower is anticipating 31.8 MW of confirmed retirements, both waste heat and wind. 174 MW of unconfirmed wind retirements may also occur over the next 10 years.
- Driven by load growth, new generation, and reliability, SaskPower is planning to expand its interconnection with SPP and add 500 MW of new transmission service over the next five years, increasing tie-line capacity to 650 MW total. Internal transmission projects totaling 180 km of new 230 kV lines are being added and an additional ~410 circuit km of transmission projects are in planning and conceptual phases over the next 5 to 10 years.
- SaskPower's primary reliability issues include growing supply chain issues that may potentially affect their significant transmission project plans and an interdependence between Southeast Saskatchewan's power generators and natural gas production fields. SaskPower has been managing these issues by scheduling long-lead-time components as early as possible in transmission project timelines and by working with Saskatchewan's gas pipeline utility to coordinate and study gas system responses to losses of production receipts during power outages as incremental demand is added.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,249	1,249	1,249	1,249	1,249
Natural Gas	2,480	2,850	2,850	2,850	2,850
Biomass	3	3	3	3	3
Wind	164	162	162	162	162
Conventional Hydro	856	856	856	856	856
Other	17	17	1	1	1
Total MW	**4,769**	**5,137**	**5,121**	**5,121**	**5,121**

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses two criteria for determining adequate generating capabilities. The first method is to calculate EUE through probabilistic modeling and maintain it within an acceptable level as determined through resource adequacy analysis. The second method employs a deterministic criterion in which the reserve margin for the Saskatchewan system must not fall below the RML.

Saskatchewan uses a RML of 15% and has assessed its PRM for the upcoming 10 years considering summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available DR for each year. During the 10-year assessment period, Saskatchewan's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year.

Energy Assessment, Including Non-Peak Hour Risk

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. A detailed representation of the SaskPower system that includes load forecasts, capacity expansion sequences, individual unit characteristics, maintenance, and outages are included in the model. For VERs, SaskPower uses the ELCC methodology to periodically update capacity credits in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. Uncertainty in assumptions is addressed through scenario work based on the likelihood of occurrence (e.g. high/low hydro energy forecast, high/low load forecast).

These studies conclude that the majority contribution to the EUE is typically planned outages with unserved energy occurring mainly during peak hours. These short-term reliability issues, when identified, can be mitigated by rescheduling maintenance.

ProbA Results

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix majorly consists of baseload and fast-ramping generation resources, and it does not have a considerable penetration level of intermittent energy resources.

The major contribution to the EUE is planned outages. The contribution to EUE in these months occurs mainly during peak hours. These short-term reliability issues when identified can be mitigated by rescheduling the maintenance.

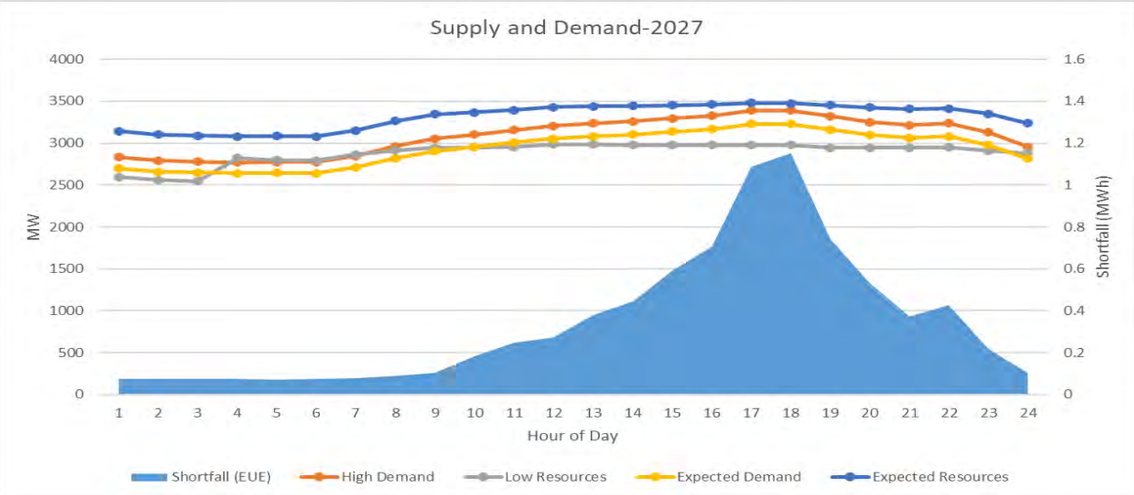
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	75	145	5
NEUE (ppm)	2.807	5.242	0.190
LOLH (hours per Year)	0.547	1.094	0.046
*** Provides the 2024 ProbA Results for Comparison**			

The annual EUE heat map for 2027 is provided below.

Hourly EUE Heat Map : 2027

EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Feb-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Mar-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Apr-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
May-27	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	3%	3%	3%	4%	5%	5%	3%	3%	2%	3%	2%	1%
Jun-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jul-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
Aug-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	1%	0%	0%
Sep-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Oct-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Nov-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dec-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2027 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, there is a risk of supply shortfalls if demand is higher than expected and resource availability is lower than expected.



Demand

Saskatchewan experiences its peak season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. SaskPower computes a coincident peak by customer category based on a combination of historical data and other factors and aggregates the coincident peaks across classes to compute the system peak.

Large industrial loads continue to be the primary reason for both growth and uncertainty in the forecast. The average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period, down slightly from the *2024 LTRA*'s projection of 1.35% average annual peak demand growth.

Demand-Side Management

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based on conditions specified in established DR programs. The first of these programs provides a curtailable load, with up to 72 MW enrolled currently, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours' notification, but those loads are not included in PRM calculations.

Distributed Energy Resources

The current behind-the-meter DER installed capacity in Saskatchewan is approximately 57 MW, which includes approximately 55 MW of solar PV and approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. Additional behind-the-meter DER installations are incorporated into load forecast models used for supply and transmission planning studies.

Small power producers contribute an additional 5 MW installed DER capacity (in front of the meter) in Saskatchewan. There is currently an existing 14 MW and a potential for up to 6.5 MW of DERs being added in the next year based on the currently approved Power Generation Partner program. These projects are included as generation additions, but their capacity is not currently considered in reliability planning.

Generation

Saskatchewan prepares a 10-year supply plan annually that outlines its generation plan to meet the province's future resource needs. It considers retirements, planned and major overhauls, degradation of unit performance, escalating fuel prices, increasing capital costs, unit operating costs, and regulatory requirements. The installed capacity of non-synchronous/inverter-based generation has recently risen to 845 MW and is expected to increase to approximately 1,550 MW in the near-term planning horizon through the addition of 400 MW of wind and 300 MW of solar in the next three years. SaskPower added 370 MW of natural-gas-fired generation in 2024, which served to offset the increased net demand variations from the 220 MW of VERs added in the same year. This resulted in a slight improvement in ramping performance as compared to the last ramping assessment in 2022. SaskPower plans to add approximately 525 MW of new natural-gas-fired generation over the next 10 years and is also working to extend the life of its operational and recently deactivated coal units as directed by the Saskatchewan government.

Saskatchewan is projecting 31.8 MW (nameplate) of confirmed retirements consisting of 21.2 MW of waste heat recovery generation and 10.6 MW of wind generation. These retirements are driven by the units approaching the ends of their lifespans and terminations of power contracts. An additional 174 MW of unconfirmed wind retirements may also materialize during the 10-year assessment period.

Energy Storage

SaskPower's first battery storage system, a 20 MW/20 MWh unit, came on-line in 2024. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/ voltage control, primary frequency control, and blackstart.

Energy Transfers

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity

transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation measures are in place through SaskPower's emergency operating procedure that will allow measures such as short-term imports from available interfaces, initiating DR, and short-term load shedding.

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Saskatchewan transmission planning region from all its neighbors, including dc-only interties, is 904 MW in the 2024 Summer and 893 MW in the 2024–2025 Winter. These values translate to approximately 25% of peak summer load and 22% of peak winter load in the analysis years. The interfaces include connections with MRO-SPP, MRO-Manitoba Hydro, and WECC-Alberta.

Transmission

SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 500 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 km of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, installation of two phase-shifting transformer interfaces, and two STATCOMs are being added. The remaining transmission projects (approximately 410 circuit km) will be in the planning or conceptual phases in the 5-to-10-year timeframe. These projects are driven by load growth, new generation additions, and reliability needs. SaskPower has historically experienced transmission limitations for existing generation deliverability in the southwest part of the province during prior outages of major transmission facilities.

Transmission infrastructure is being developed to reinforce the Northern Transmission System. SaskPower's Northern System is not directly connected to the Southern grid, so significant load growth in the North will also require additional generation to supply the additional loads. SaskPower is looking at different ways to supply the generation to this load, including wheeling power from the South to the North through adjacent areas and temporary generation until a more permanent solution can be implemented. Planning for these projects is being driven, in part, by a projected increase in mining activity and associated development in Saskatchewan's remote northern region. Reliable power supplies for new loads in the north will require significant transmission development.

Reliability Issues

As SaskPower is planning on constructing a significant number of transmission facilities, growing supply chain issues may affect project schedules because of long lead times for major system components. SaskPower is identifying and initiating projects earlier that may require longer lead time and is advancing procurement as necessary.

It has been noted that there is an interdependency between Southeast Saskatchewan's power generation and natural gas production. Saskatchewan's pipeline utility, SaskEnergy, has completed analysis on how its system will respond to a loss of natural gas receipts during a power outage in this region as potential incremental demand is added. Both SaskPower and SaskEnergy have incorporated the potential challenges identified by that analysis into long-term planning and mitigation efforts.

SaskPower has been recently observing increasing instances of unscheduled flows on its interface with SPP and Manitoba Hydro. SaskPower is coordinating this on a regional basis with Manitoba Hydro, SPP and MISO to monitor and address the impact.

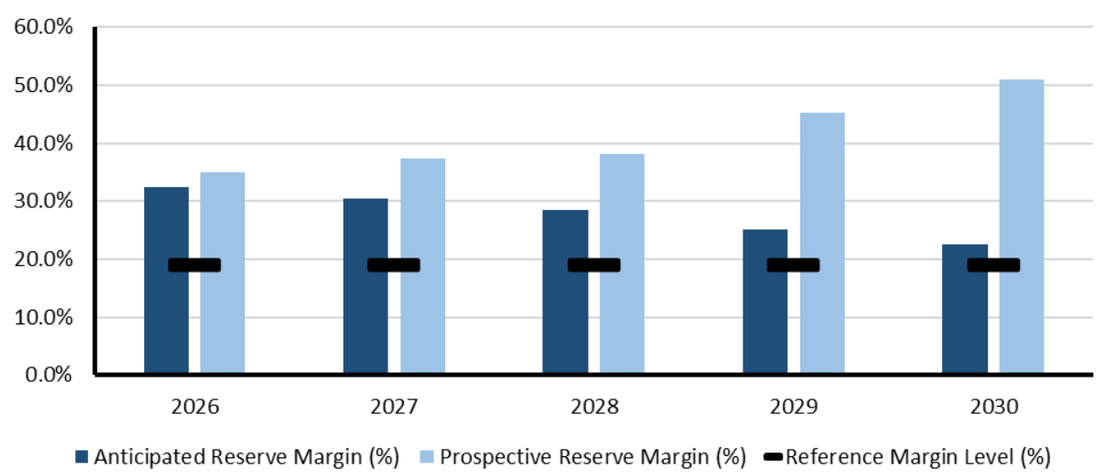


MRO-SPP

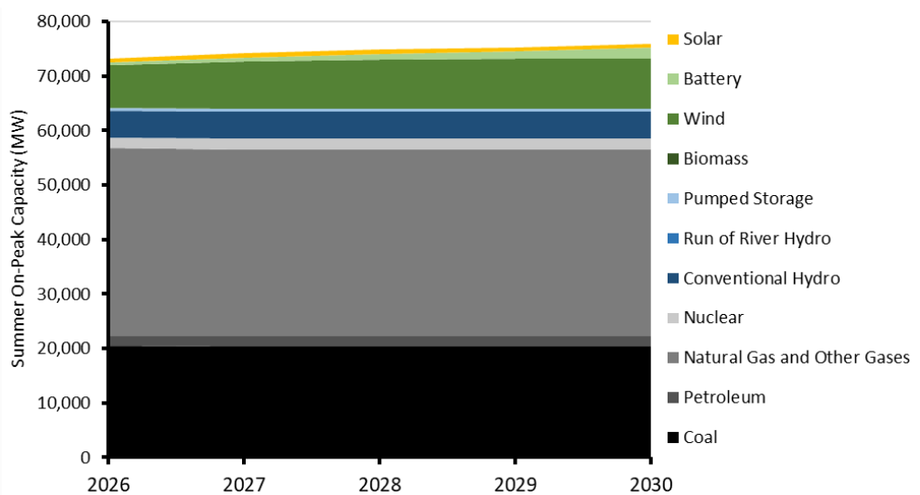
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization 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.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	57,479	59,121	60,689	62,766	64,475	66,283	66,982	67,570	68,049	68,622
Demand Response	2,138	2,162	2,332	2,508	2,509	2,511	2,513	2,514	2,718	2,720
Net Internal Demand	55,340	56,959	58,357	60,258	61,966	63,772	64,469	65,056	65,331	65,902
Additions: Tier 1	1,808	3,020	3,685	4,251	4,815	4,866	5,344	5,344	5,344	5,344
Additions: Tier 2	2,436	6,104	8,948	15,659	21,487	23,345	25,664	27,277	27,877	28,627
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-18	-78	-78	-78	-78	-79	-79	-79	-79	-79
Existing-Certain and Net Firm Transfers	71,475	71,224	71,232	71,127	71,146	71,115	71,135	71,106	71,105	71,106
Anticipated Reserve Margin (%)	32.4%	30.3%	28.4%	25.1%	22.6%	19.1%	18.6%	17.5%	17.0%	16.0%
Prospective Reserve Margin (%)	34.9%	37.3%	38.2%	45.2%	50.9%	48.7%	51.5%	51.8%	51.8%	50.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SPP Highlights

- The SPP assessment area peak demand occurs during the summer season; the 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023.
- SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026.
- The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	20,473	20,440	20,440	20,428	20,428
Coal*	19,187	19,154	18,086	18,075	18,075
Petroleum	1,824	1,827	1,827	1,827	1,829
Petroleum*	1,824	1,771	1,771	1,771	1,774
Natural Gas	34,525	34,303	34,303	34,265	34,265
Natural Gas*	34,363	33,662	33,550	33,512	33,268
Biomass	35	35	35	35	35
Solar	700	700	700	700	700
Wind	7,831	8,581	9,044	9,134	9,191
Conventional Hydro	4,925	4,993	5,009	5,026	5,030
Pumped Storage	456	456	456	415	460
Nuclear	1,945	1,945	1,945	1,945	1,945
Other	281	281	281	281	281
Battery	379	833	1,027	1,472	1,949
Total MW	73,429	74,450	75,123	75,584	76,168
Total MW*	71,981	72,467	71,960	72,422	72,762
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029. SPP has approved a non-coincident 16% PRM for the 2026 Summer season and a 36% PRM for the 2026–2027 Winter season. Additionally, a non-coincident 17% PRM for the 2029 Summer season and 38% PRM for the winter season was approved as well. The PRM increases are not reflected in the *2025 LTRA* as they are tied to policies that are still before FERC. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to drop below the current 19% RML in 2032 and remain below that RML for the remainder of the 10-year horizon.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

SPP is performing a yearly energy adequacy assessment and assessment of adequacy of reliability attributes, which will be presented to SPP stakeholders. The results will also be used to perform for all reliability attributes a biennial assessment of the need for new market products, changes to market functionality, and changes to resource adequacy policies or requirements. Results of the biennial reassessment will be provided to impacted SPP stakeholder groups and the Regional State Committee (RSC).

Southwest Power Pool (SPP) performs an LOLE analysis every two years to determine the adequate amount of planning reserves needed to maintain a reliability metric of one day (or less) in ten years. SPP's 2023 LOLE study supported much of the demand forecast presented in NERC's *2024 LTRA* and demonstrated how the PRM could be impacted materially depending upon how much loss of demand risk was planned for each season (winter or summer). Directed by the RTO's Resource and Energy Adequacy Leadership Team, SPP completed an out-of-cycle 2024 LOLE analysis published in April 2025 to develop a recommendation for 2029 seasonal PRMs. This study and its results are based on the 2024 member-submitted forecast for the resource mix and demand, using the 2023 LOLE study assumptions. Member-submitted demand forecast increased approximately 5% in summer and 6% in winter for planning year 2029.

ProbA Results

The 2025 ProbA study was performed on assumptions, and the accompanying methodology reflects methods used in SPP's LOLE studies, which have been thoroughly vetted through the SPP stakeholder process. Study improvements include additional weather years, seasonal forced outage modeling from the previous NERC probabilistic study, and incremental cold weather outages. More information on improvement and methodology can be found in SPP's LOLE study reports.

There was no observed unserved energy for years two and four of the base-case analysis for the SPP assessment area. This is most likely attributed to an increase of conventional thermal generations more than that of renewable resources and the delayed retirements of other thermal resources to meet the increasing projected demand needs. Since there are no observed load-loss events, additional reporting is not provided.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
***Provides the 2024 ProbA Results for Comparison**			

Demand

The SPP assessment area is a summer-peaking region and currently relies on the forecast submitted by the load responsible entities in the annual resource adequacy process. The 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023. Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecasted net internal demands are based on a 10-to-30-year average of summer weather, or 50/50 weather. Some SPP RTO members base their peak load forecasts on a 50% confidence level, as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. SPP RTO members make economic assumptions in their individual forecasting methods as well consider the effects of non-controllable or dispatchable programs and resources within their area. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has seen in recent peak season.

Although SPP's energy projections for resource adequacy purposes differ from load interconnection process set forth in the SPP OATT, the SPP Assessment Area has received new load requests for data center, pipeline, oil and gas, irrigation and industrial load. While these loads represent above average load growth in areas, some of the load due to oil and gas exploration have decreased. Of current concern is the projected growth in the crypto load area and how much of that will turn into demand growth outside of the DR arena.

Demand-Side Management
SPP RTO members track dispatchable and controllable DR programs, which are used as peak load shaving programs. For resource adequacy purposes, the peak demand can be reduced by the impacts of the programs to determine an appropriate net peak demand for each member. SPP's tariff requires each Load Responsible Entity (LRE) to qualify and test their programs to prove they can meet and maintain the level of reduction submitted annually in the resource adequacy compliance window. SPP is constructing new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources
The SPP assessment area is forecasting ~70 MWs of DERs in the 5–10-year planning horizon. The impacts and assumptions may differ across the planning processes, for instance in some studies they may be used to reduce the load impacts whereas in other studies they may be modeled as a resource that has a high cost associated with it. SPP does not consider the impacts of BTM resource as a load reduction for purposes on resource adequacy compliance.

Generation
In general, SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026. There has been minimal retirement reported since the *2024 LTRA*, and a number of resources identified in 2024 as being set to retire are now being converted to new fuel, mostly coal to gas.

The *Expedited Resource Adequacy Study* process, approved by FERC in July 2025, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs. The program is yielding additional natural-gas-fired, solar, and battery resource projects in SPP's Tier 2 development queue. Nearly 8 GW of natural-gas-fired generator capacity, 2.2 GW nameplate in solar, and 1.8 GW nameplate in batteries have been added to SPP's Tier 2 queue since July and are not reflected in this year's LTRA. SPP anticipates the first interconnection agreements for *Expedited Resource Adequacy Study* projects will be signed in early 2026, which will qualify these resources for Tier 1 in NERC's reliability assessments and ProbA and count toward ARM.

Energy Storage
There are approximately 57,000 MWs of energy storage and hybrid resources in generator interconnection queues. There are about 50 MWs that are under contract by members across the SPP assessment area and 230 MW of nameplate capacity forecasted for the assessment timeframe. These resources are being modeled as generation in the planning assumptions both near and long term. Due to this limited amount of storage, limited operational impacts have been identified.

Capacity Transfers
Over the assessment time frame, SPP is forecasting, based on submitted member data, to be a net exporter of capacity. In the resource adequacy process, SPP only relies on the imports that have firm transmission service, which is ~2,000 MWs. SPP and ERCOT executed a Coordination Plan, which addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the Coordination Plan based on the latest discussions and business decisions related to resource priority.

Transmission
SPP's 2024 Integrated Transmission Plan (ITP) is the single largest portfolio, in terms of size and value, that SPP has proposed for construction in its 20-year history as a transmission PC. The approved plan includes 89 transmission upgrades needed to address increasing electricity consumption and changes in the region's generating fleet.

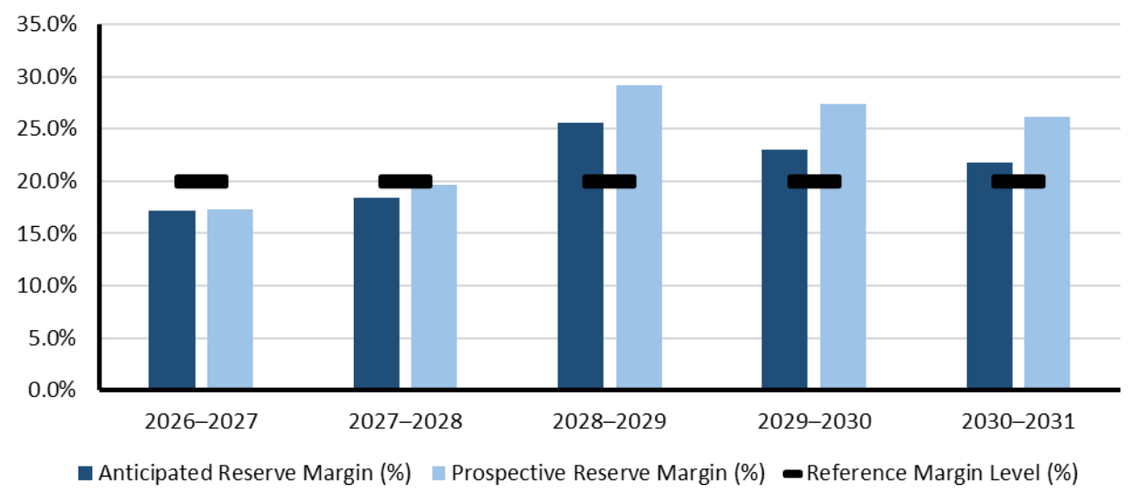


NPCC-Maritimes

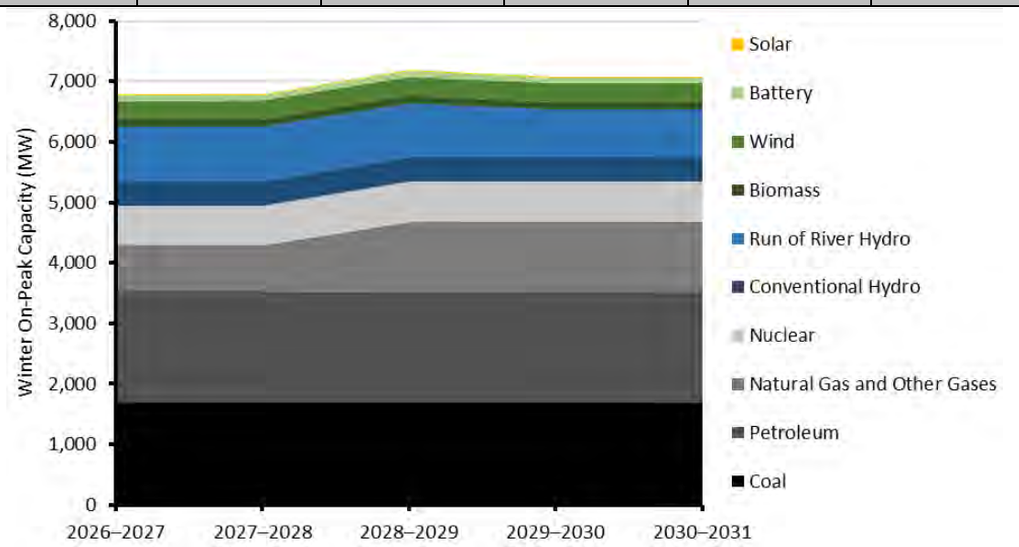
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	6,107	6,157	6,194	6,231	6,292	6,346	6,380	6,493	6,579	6,669
Demand Response	264	283	290	291	290	291	290	291	290	290
Net Internal Demand	5,843	5,875	5,904	5,940	6,001	6,055	6,089	6,202	6,289	6,380
Additions: Tier 1	173	179	579	579	579	579	579	579	579	579
Additions: Tier 2	6	367	656	1,492	1,492	1,492	1,492	1,492	1,492	1,492
Additions: Tier 3	0	0	23	101	215	227	239	251	260	260
Net Firm Capacity Transfers	-32	75	145	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,673	6,780	6,838	6,727	6,727	6,727	6,621	6,621	6,596	6,707
Anticipated Reserve Margin (%)	17.2%	18.5%	25.6%	23.0%	21.7%	20.7%	18.2%	16.1%	14.1%	14.2%
Prospective Reserve Margin (%)	17.3%	19.6%	29.2%	27.4%	26.1%	25.0%	22.6%	20.3%	18.3%	18.3%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Maritimes Highlights

- Since the *2024 LTRA*, the overall resource outlook has diminished slightly with smaller peak capacity contributions from certain wind, hydro, and biomass resources through most of the planning period. Starting in 2026, winter peak demand forecasts for this assessment area have risen slightly from the previous year's projection through most years of the planning horizon; however, ARMs are currently projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,410	1,003	691
Petroleum	1,831	1,831	1,820	1,820	1,820
Natural Gas	757	757	1,157	1,157	1,157
Biomass	129	129	129	129	129
Solar	10	10	10	10	10
Wind	300	306	306	306	306
Conventional Hydro	395	395	395	395	395
Run of River Hydro	901	901	901	790	790
Nuclear	663	663	671	671	671
Other	98	98	89	89	89
Battery	99	99	99	99	99
Total MW	6,878	6,884	7,272	7,161	7,161
Total MW*	6,878	6,884	6,986	6,468	6,156
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The RML that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas comprising the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM over the study period for the Maritimes area ranges between 14% to 26% during the winter period and between 74% to 90% during the summer period.

The ARM level during off-peak season for the Maritimes areas ranges between 74% to 90%. During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

The two BAs within the Maritimes area, as members of the NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

Energy Risk

During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy, needs and hence there are no constraints with converting the capacity to energy during these times.

The two Balancing Authorities within the Maritimes Area as members of the Northeast Power Coordinating Council (NPCC) jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual and seasonal ProbAs, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

ProbA

For the Maritimes area, the ProbA indicates elevated levels of unserved energy in February 2028 due to load growth projections and the characteristics of the resource mix during that period and with a few hours of risk in the shoulder months of December and January.

Annual metrics and requested enhancements including EUE heat maps, loss of load event analysis, and risk period visualizations for both 2027 and 2029 are included in the ProbA appendix.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	**5**	**15**	**7**
NEUE (ppm)	**0.17**	**0.52**	**0.25**
LOLH (hours/year)	**0.09**	**0.25**	**0.10**
*Results from the 2024 ProbA simulations			

Resource additions described in the Generation section below contribute to the improved EUE and LOLH metrics for study year 2029.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period.

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.8% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.6% during the 10-year assessment period for an average growth of 0.7% per year. Demand and energy forecasts have risen since the *2024 LTRA*, due in large part to rural-to-metropolitan population migration and the proliferation of heat pump technology in local areas previously heated by fossil fuels, primarily in the PEI region.

Demand-Side Management

Plans to develop up to 100 MW by 2030–2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 21 MW to 147 MW

while the annual amounts for winter peak demand reductions rise from 177 MW to 652 MW. [37] The total controllable and dispatchable DR increases from 328 MW to 337 MW in the summer period while increasing from 248 MW to 290 MW in the winter period.

Distributed Energy Resources

The DER installed capacity in NS is approximately 300 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar.

LTRA wind capacity for NB, NS, and PEI is de-rated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. Behind-the-meter (BTM) solar is assumed to have an ELCC of 0% during the winter period. The Maritimes area has shown embedded BTM solar PV projections of 204 MW in 2025 rising to 1,261 MW by 2035. These projects include distributed small-scale solar (mainly rooftop) projects that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area's system peak which occurs either before sunrise or after sunset in the winter period.

Generation

NB plans to extend 28 MW diesel fired generator starting in 2025 and recently upgraded 277 MW of natural-gas-fueled resource completed in 2023. An anticipated replacement PPA contract, a long-term firm energy contract from neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

In New Brunswick, Tier 1 resources include 63 MW (installed capacity) of wind and 400 MW of combustion turbines. Tier 2 resources include 546 MW of wind resources and 72 MW of biomass.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 635MW phased-in from 2025–2027. These projects include 306 MW as part of the provincial Rate Base Procurement program, a 168 MW wind project, a 12.5 MW wind project, and a 148 MW wind project under the Renewable to Retail tariffs. Tier 1 resources in NS also include a 150 MW battery (2025–2026). Tier 2 resources in NS include 600 MW of combustion turbines (2027–2029); a 150 MW conversion of a coal-fired unit to natural gas (2028); 459 MW conversion of coal-fire units to oil (2030); 250 MW of batteries (2027–2029); 262 MW of wind projects as part of the provincial Green Choice Program (2028–2029); and approximately 100 MW of solar independent power producer (IPP) projects (2026-2029) with an ELCC of 0%. Tier 3 resources in NS include new wind generation with a nameplate capacity of 1400 MW phased in from 2029-2034.

PEI has 30 MW installed capacity of tier 2 wind, 111 MW tier 3 wind, 140 MW of tier 3 Petroleum based generation and 10 MW of tier 3 batteries.

NB de-rates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI de-rate wind capacity to 18% and 17% respectively of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes Area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource (2025–2026) and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource (2027–2029). These grid scale projects will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 3 resource starting summer of 2028.

NB Power has not included any energy storage resources in the *2025 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest (REOI) for new renewable generation sources, including 200 MW wind, 15 MW solar, 5 MW tidal, and 50 MW 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources such as wind to provide additional flexibility to the system.

[37] Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Capacity Transfers
Probabilistic studies show that Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission
NS has multiple new transmission line projects compared to the 2025 LTRA, most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues
The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 32% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during the assessment period.



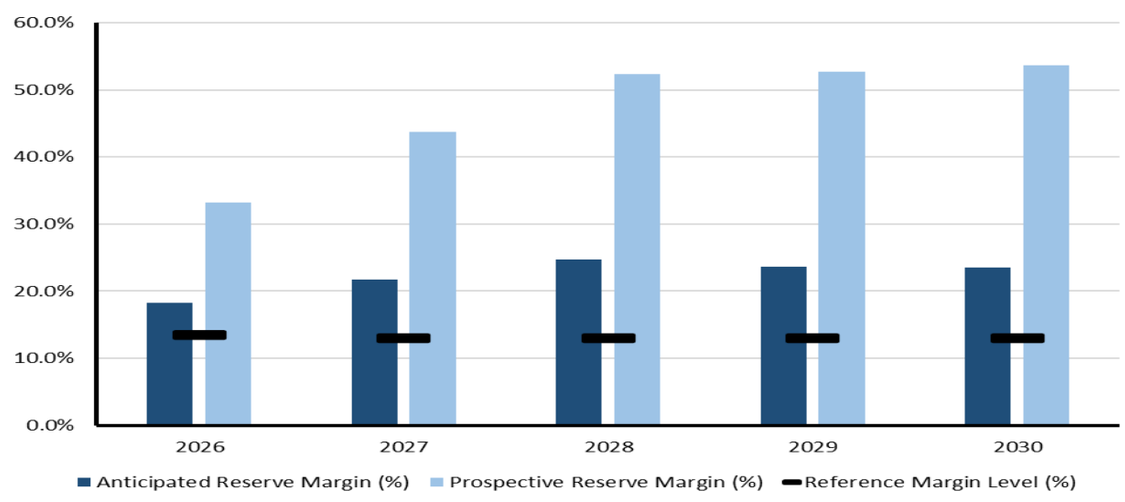
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization 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.

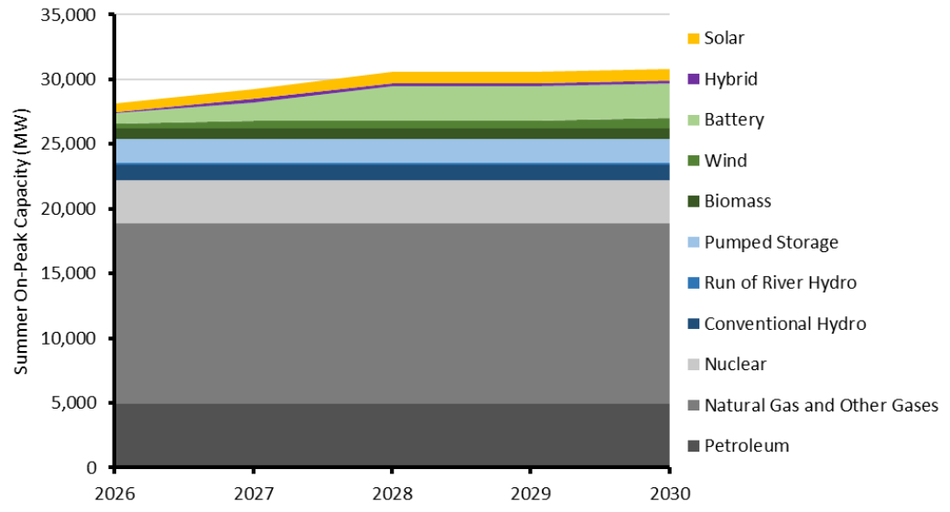
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	24,877	24,945	25,124	25,347	25,557	25,821	26,123	26,486	26,897	27,331
Demand Response	623	544	544	544	544	544	544	544	544	544
Net Internal Demand	24,254	24,401	24,580	24,803	25,013	25,277	25,579	25,942	26,353	26,787
Additions: Tier 1	1,081	2,183	3,543	3,551	3,781	3,781	3,913	3,913	4,263	4,263
Additions: Tier 2	1,113	2,871	4,274	4,687	5,037	5,037	5,037	5,387	5,387	5,387
Additions: Tier 3	872	4,129	10,335	11,426	11,830	12,924	12,924	12,924	12,924	12,924
Net Firm Capacity Transfers	567	465	84	84	84	84	84	0	0	0
Existing-Certain and Net Firm Transfers	27,607	27,505	27,124	27,124	27,124	27,124	27,124	27,040	27,040	27,040
Anticipated Reserve Margin (%)	18.3%	21.7%	24.8%	23.7%	23.6%	22.3%	21.3%	19.3%	18.8%	16.9%
Prospective Reserve Margin (%)	33.2%	43.7%	52.3%	52.7%	53.7%	52.1%	50.8%	49.7%	48.7%	46.3%
Reference Margin Level (%)	13.4%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New England Highlights

- New England is forecast to have sufficient seasonal ARMs needed to meet consumer demand for electric energy for the entire assessment period (2026–2035) and not require any Tier 2 resources.
- Ongoing developments of wind facilities and a new interregional tie with Canada (the New England Clean Energy Connect) as well as new technologies (such as longer-duration electricity storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.
- The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[38]					
	2026	2027	2028	2029	2030
Petroleum	4,899	4,899	4,899	4,899	4,899
Natural Gas	13,939	13,939	13,939	13,939	13,939
Biomass	776	776	776	776	776
Solar	645	726	864	872	872
Wind	416	622	622	622	852
Conventional Hydro	1,165	1,165	1,165	1,165	1,165
Run of River Hydro	179	179	179	179	179
Pumped Storage	1,864	1,864	1,864	1,864	1,864
Nuclear	3,351	3,351	3,351	3,351	3,351
Hybrid	96	287	287	287	287
Battery	791	1,416	2,638	2,638	2,638
Total MW	28,121	29,223	30,584	30,591	30,821

- The winter ARMs do not fall below the annual RMLs for the entire assessment period.

[38] MW totals reflect existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

The winter ARMs do not fall below the annual RMLs for the entire assessment period. The winter ARMs range from a surplus high of 10,651 MW (66% ARM) in winter 2027–28 and then decrease each year to a surplus low of 4,522 MW (30% ARM) in winter 2035–36. The larger surpluses during winter (vs. summer) reflect the fact that New England is currently summer-peaking.

With the continued development of renewable and clean energy resources, the system will continue to emit lower air emissions.

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet NPCC's resource adequacy reliability criterion. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period (CCP). The latest ICR calculations result in an LTRA annual RML of 13% in 2026 and 2027, expressed in terms of the annual 50/50 peak demand forecast. For the years 2028 through 2035, ISO-NE continued to use the last available RML value of 13%.

Energy Risks (Including Non-Peak Hour Risk)

ISO-NE routinely prepares a 21-day energy assessment forecast and report. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the regional supply/demand balance is projected to be negative, then projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure whatever is necessary (fuel) to follow future ISO dispatch orders. ISO-NE publishes its 21-day energy assessments every 2 weeks during spring, summer, and fall and then increases these publications to weekly (and/or daily if necessary) during the winter.

ISO-NE worked with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. The modeling results for the near-term PEAT assessments show for Summer 2027 that no energy shortfalls were observed in any of the events. One operating reserve shortfall was observed within a long-duration heat wave coincident with low wind scenario. For Winter 2027, a range of energy shortfall risks and associated probabilities were observed:

- The energy shortfall risk appears manageable over a 21-day period.
- These modeling results are consistent with the significant quantities of PV (BTM and utility scale), wind, and energy/electricity storage expected while experiencing minimal load growth.
- Operating risks may be mitigated by incremental imports from large inter-area transmission interconnects.

The modeling results for Summer 2032 also show that no energy shortfalls were observed in any of the hours of the 21-day period and only 1 hour of 30-minute reserve shortfall was observed. Baseline studies of Summer 2032 events indicate an energy shortfall risk similar to that of Summer 2027 events.

The modeling results for Winter 2032 show that the energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. These results also reveal the range of energy shortfall risk under a variety of resource mix and demand assumptions. In terms of magnitude and probability, baseline studies of Winter 2032 events indicate an energy shortfall risk profile akin to that of Winter 2027 event studies.

Probabilistic Assessments (ProbA and Other Studies)

In conjunction with NPCC, ISO-NE conducts annual probabilistic resource adequacy assessments to identify regional capacity resource needs and to comply with NPCC/NERC reliability criterion/requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue in support of the New England states' policy objectives of providing access to a greater diversity of clean energy resources and to comply with environmental regulations.

New England is a summer-peaking area. For the ProbA years, New England presents negligible risks in 2027 and very low risk in 2029 based on the ProbA results shown below.

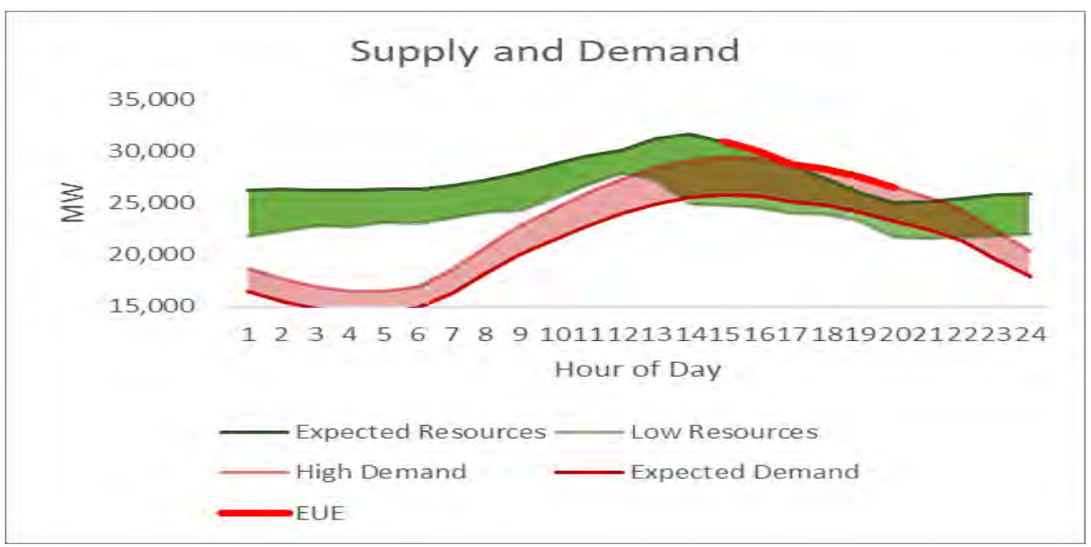
NPCC New England Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

EUE Heat Map – 2029

For the 2029 summer season, the highest EUE risks are driven by high demand and low resources availability.

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	10%	33%	24%	1%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	19%	5%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

The figure below illustrates hourly demand and resource projections for the highest EUE day in 2029.



Demand

For its 2025 forecast, ISO-NE has updated its long-term forecast methodology to include hourly modeling of all load components, incorporation of climate-adjusted weather in forecast simulation, redefinition of gross load to reflect reconstitution for BTM solar PV (BTM PV) only, and an expanded forecast horizon that extends to 2045. This new base load forecast also already implicitly accounts for the load reduction from EE.

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,094 MW from 24,803 MW in 2025 to 26,897 MW in 2034. The corresponding net internal winter peak demand increases by 5,964 MW from 20,056 MW in 2025–26 to 26,020 in 2034–35. Net energy for load is forecast to grow by 13,403 GWh from 117,262 GWh in 2025 to 130,665 GWh in 2034. These peak growth projections have not changed significantly since the *2024 LTRA*. The energy growth projection has decreased as well since the *2024 LTRA*.

The higher winter peak growth rate due to anticipated electrification results in convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by that time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management (DR/DSM)/Distributed Energy Resources (DER)

For Summer 2026, ISO-NE forecasts 623 MW of controllable and dispatchable DR/DSM resources, which is projected to decrease to 544 MW by the summer of 2027. That value is then held constant through the rest of the assessment period.

For summer months, the results of the BTM PV forecast are incorporated into the ISO-NE gross demand forecast as estimated reductions in demand. In the summer of 2026, New England is expected to have 1,759 MW (5,093 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,942 MW (7,359 MW nameplate) by 2031. The winter capacity contribution for BTM PV resources is currently 7 MW (5,372 MW nameplate) in the winter of 2026–27 and increases to 521 MW (9,360 MW nameplate) in the winter of 2035–36.

In 2024, ISO-NE developed a new Planning Procedure 12 entitled *Data Collection for Distributed Energy Resources* to formalize and standardize data collection for DERs. Under this new planning procedure, distribution providers are responsible for providing installation-level data on DERs connected to their system (these DERs do not include DR, controllable loads, or other load modifiers). Additionally, transmission providers are responsible for providing data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits, this planning procedure will allow for proper accounting of the location, size, and type of DER, which will lead to more accurate operational and planning studies.

Generation

The two largest changes that will impact New England's generation fleet are the changes to the methodology for capacity accreditation and the development of a seasonal, prompt capacity market. Efforts are underway to change the timing and commitment horizons of capacity auctions to

seasonal/prompt in preparation for the evolving resource mix the Capacity Auction Reforms Key Project.

While ISO-NE does not expect any reliability impacts due to the retirement of any one single unit or station, the past and future retirements of dispatchable, fossil-fueled capacity, with on-site fuel inventories, as well as potential nuclear plant retirements, continue to exacerbate known winter reliability issues related to natural gas availability.

Energy Storage

New England has a total of 2,331 MW/2,110 MW (summer/winter rating) of energy storage capacity. Among the largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,864 MW / 1,861 MW (summer/winter rating) of quick-start 10-minute operating reserve capability, and with full reservoirs, can produce over 11,800 MWh of energy.

New England currently has 467 MW/249 MW (summer/winter rating) of electricity storage, including traditional battery storage along with integrated hybrid and co-located hybrid electricity storage.

As of April 1, 2025, there were 16,885 MW (summer ratings) of electricity storage devices (batteries, integrated-hybrid, and co-located-hybrid) that have submitted interconnection requests for installation over the next five years under the combined resource categories of Tier 1 at 2,658 MW, Tier 2 at 3,258 MW, and Tier 3 at 10,969 MW.

No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase/decrease from their 5-year projection.

Capacity Transfers (Reliance on Assistance)

New England is interconnected to three BAs: Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to meet the regional resource adequacy criterion while preventing over-reliance on such assistance. Assumed assistance from tie benefits ranges from 2,100 MW in 2026 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 567 MW in the summer of 2026 to 84 MW in the summer of 2028. There is one long-term firm import contract of 84 MW that extends from Summer 2028 through Summer 2032.

Within the *2025 LTRA* Prospective Resources (and Prospective Reserve Margin in the Demand, Resources, and Reserve Margins table), a summer and winter, energy-only contract is identified (i.e., expected imports). These numbers reflect the upcoming commercialization (in late 2025) of the New England Clean Energy Connect (NECEC), a new 1,200 MW tie line connecting Québec to Lewiston, Maine. An off-take 1,090 MW energy-only contract into Maine/New England has been executed. This import of 1,090 MW reflects the average hourly rate of the total annual energy in the contract.

In addition, there are no firm exports identified over the 10-year LTRA summer or winter assessment periods.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs that use inverter-based technology and changes to mandatory planning criteria promulgated by NERC and NPCC have driven the need for increasingly complex transmission assessments.

The future reliable and economic performance of the system is expected to continue to improve because of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of inverter-based technologies, and issues arising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. ISO-NE's longer-term transmission planning process was developed through coordination with NESCOE to create an additional path toward meeting these future system needs.

Reliability Issues

New England's power system is transitioning to a system with unprecedented projected demand growth and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE has been engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall power system reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected "in-service" dates for transmission system upgrades due to supply chain issues. In these cases, ISO-NE develops special operating plans to work around any issues caused by these commercialization delays.

New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. In winter, the interstate natural gas pipelines serving New England run full with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. In response, ISO-NE has been a key player at the national level in promoting electric/gas

communications/coordination, sharing of lessons learned, best practices, and more recently, through the performance of more detailed and in-depth deterministic and probabilistic energy assessments.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy/electricity—either through long-term energy/electricity storage solutions that can capture and store renewable power or through the use of flexible, dispatchable resources.

ISO-NE is actively working on numerous major projects as part of its energy transition while ensuring continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- Capacity Auction Reforms
- Operational Impacts of Extreme Weather Events
- Day-Ahead Ancillary Services Initiative
- 2024 Economic Study
- Extended-Term Transmission Planning Tariff Changes (aka Longer-Term Transmission Planning (LTTP) Tariff Changes)
- Longer-Term Transmission Studies
- Storage As Transmission Only Asset
- FERC Order No. 1920 Project
- FERC Order No. 2023 Project
- FERC Order No. 2222 Project

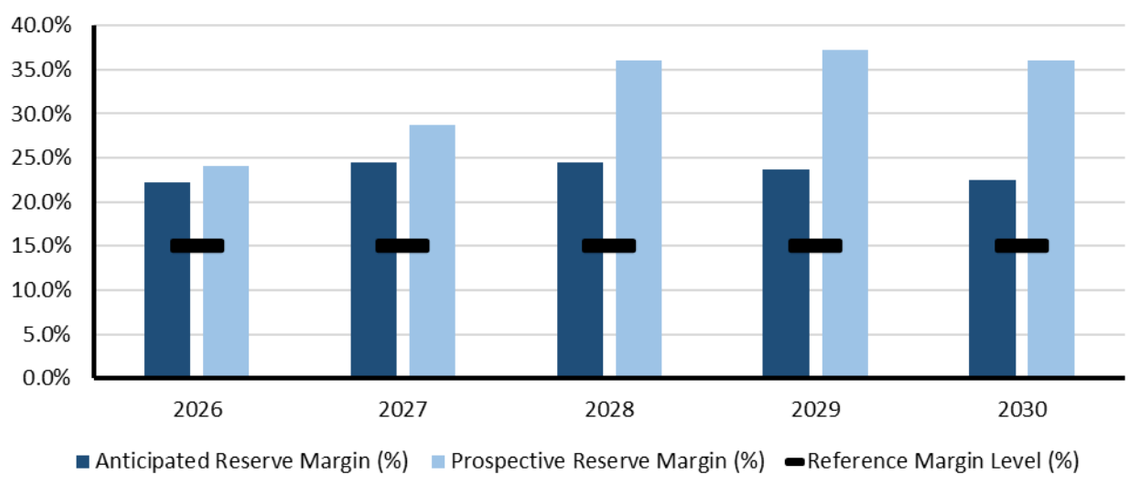


NPCC-New York

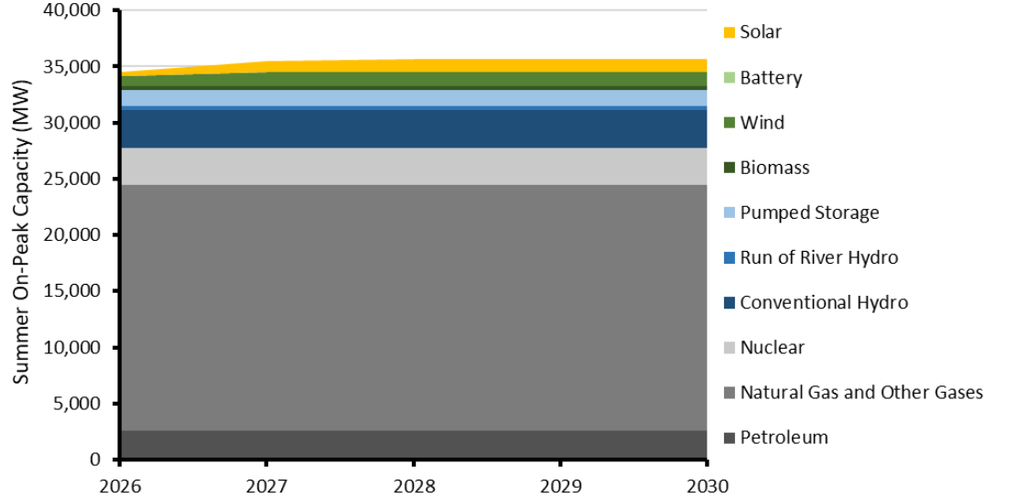
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, 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 (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	31,990	32,280	32,410	32,620	32,910	33,190	33,520	33,870	34,170	34,500
Demand Response	989	989	989	989	989	989	989	989	989	989
Net Internal Demand	31,001	31,291	31,421	31,631	31,921	32,201	32,531	32,881	33,181	33,511
Additions: Tier 1	532	1,509	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660
Additions: Tier 2	574	1,317	3,642	4,313	4,313	4,313	4,313	4,313	4,313	4,313
Additions: Tier 3	150	1,516	9,280	19,034	25,847	28,035	28,035	28,526	29,009	29,009
Net Firm Capacity Transfers	3,405	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486
Existing-Certain and Net Firm Transfers	37,368	37,449	37,450	37,450	37,450	36,995	36,995	36,995	36,995	36,995
Anticipated Reserve Margin (%)	22.3%	24.5%	24.5%	23.6%	22.5%	20.0%	18.8%	17.6%	16.5%	15.4%
Prospective Reserve Margin (%)	24.1%	28.7%	36.1%	37.3%	36.0%	33.4%	32.1%	30.7%	29.5%	28.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New York Highlights

- Generator deactivations are outpacing new supply additions. Electrification programs and new large-load customers associated with economic development initiatives are pushing projected demand higher. Together, these forces are also narrowing reliability margins across New York and increasing the risk of future reliability needs.
- As public policy goals seek to decarbonize the grid, fossil-fired generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. EE and demand-side management (DSM) will continue to play a key role in reducing energy consumption, lowering costs, and mitigating environmental impacts.
- Some of the risks can be mitigated by repowering. Repowering aging power plants can lower emissions, meet rising consumer demand, and provide reliability benefits to the grid that are needed to integrate additional clean energy resources.
- New York is projected to become a winter-peaking electric system by the 2040s, driven primarily by electrification of space heating and transportation. On the coldest days, the availability of natural gas for power generation can be limited, and interruptions to natural gas supply will introduce further challenges for reliable electric grid operations.
- Driven by public policies, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection processes continue to evolve to balance developer flexibility with the need to manage the process to more stringent time frames. New processes have been implemented to accelerate the process while protecting grid reliability.
- The competitive wholesale electricity markets administered by NYISO support reliability while minimizing costs to consumers. Competitive wholesale markets are essential to a reliable, affordable, and cleaner grid of the future.
- NYISO's *2025 Quarter 3 Short-Term Assessment of Reliability* (STAR)[39] report identified short-term reliability needs in New York City and Long Island due to generation deactivations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	2,597	2,597	2,597	2,597	2,597
Natural Gas	21,858	21,858	21,858	21,858	21,858
Biomass	334	334	334	334	334
Solar	345	931	1,083	1,083	1,083
Wind	850	1,221	1,221	1,221	1,221
Geothermal	0	0	0	0	0
Conventional Hydro	3,324	3,324	3,324	3,324	3,324
Run of River Hydro	418	418	418	418	418
Pumped Storage	1,411	1,411	1,411	1,411	1,411
Nuclear	3,326	3,326	3,326	3,326	3,326
Hybrid	0	0	0	0	0
Other	0	0	0	0	0
Battery	32	52	52	52	52
Unknown	0	0	0	0	0
Total MW	34,495	35,472	35,623	35,623	35,623

[39] NYISO's *2025 Q3 STAR Report*: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf; Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; and Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2024 Reliability Needs Assessment*[40] found reliability margins decrease over time as load increases to the point that New York is nearly at the 0.1 even-days/year criteria by 2034.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC's resource adequacy criterion of "one day in 10 years." The current IRM for the 2025–2026 capability year is 24.4% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 24.4%. Additionally, NYISO performs an annual study to identify the Locational Minimum Installed Capacity Requirements (LCRs) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's Climate Leadership and Community Protection Act (CLCPA) decarbonization mandates to decarbonize span all major industries and are the main drivers of change to the electric system NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement, and certain combined-cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes, as well as supporting the calculation of the annual IRM, LCRs, and capacity accreditation. The new capacity accreditation market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The CAFs will reflect the marginal reliability contribution of the ICAP suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

Additionally, every year, each Regional Entity (e.g., NPCC) provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2025 by the NPCC Regional Entity are shown below.

ProbA Results

New York is a summer-peaking area with negligible risks as shown in the low values in the following table of annual metrics.

[40] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

EUE Heat Maps – 2029

Negligible risk presented for Summer 2029, with occurrences clustered in July and August around hours 16 to 18.

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	7%	24%	25%	7%	3%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	8%	16%	6%	1%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2029 are shown in the figure below.



Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the higher net demand levels from LFU compounded with a greater risk added due to the variability in resource contribution. The higher net demand LFU levels could be 10–13% higher than expected, which could strain the system as modeled in the ProbA.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as electric vehicle charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+1.0%) growth rates are similar to last year's forecast. Throughout the 30-year forecast period, baseline energy and seasonal peak demand increase significantly due to New York State electrification and decarbonization policies, principally the CLCPA. The baseline forecast includes significant electrification via conversion to electric heating and electric non-weather sensitive appliances, along with significant growth in EV adoption. In the early forecast years, large-load projects add significant growth to the annual energy and peak demand forecasts. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO has been working on developing market concepts to encourage the participation of flexible load, which participation will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy

policies. New York utilities are piloting several load management programs (e.g., smart electric vehicle charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the 2025 LTRA, the DR participation for the summer capability period has increased slightly from 1,294 MW to 1,487 MW. These values are nameplate and are derated for reserve margin calculations. For example, the 1,487 MW is derated to 989 MW. There are currently 433 MW of DR participating in ancillary services programs (not included in reserve margin calculations) and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

In 2024, NYISO implemented a plan to integrate DERs, including DR resources, into its markets. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single-participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

Significant new resource development will be required to achieve New York's energy targets under the CLCPA. According to the 2023–2042 System and Resource Outlook the total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply and meet policy requirements within the next 20 years.

Currently, NYISO's interconnection process[41] contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. The New York system relies on fossil-fuel, synchronous generation. ERSs usually provided to the system by synchronous fossil generation will remain necessary. As New York's public policies seek to decarbonize the grid, fossil-fuel, synchronous generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation.

On June 23, 2025,[42] New York's governor directed the New York Power Authority to develop and construct a zero-emission advanced nuclear power plant in upstate New York to support a reliable and affordable electric grid while providing the necessary zero-emission electricity to achieve a clean energy economy.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is preparing the implementation of a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resource models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with its neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO limits emergency assistance from neighboring systems by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighboring systems.

[41] https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx

[42] https://www.governor.ny.gov/news/governor-hochul-directs-new-york-power-authority-develop-zero-emission-advanced-nuclear-energy

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring systems. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring systems will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City, and
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new ac tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030
- Con Edison's proposed Brooklyn Clean Energy Hub project, including a new 345 kV load-serving substation with the goal of addressing local electric reliability needs in the boroughs of Brooklyn and Queens as well as the goal of serving as a point of interconnection for new clean-energy resources

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emission-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

NYISO's *2024 Reliability Needs Assessment*[43] (RNA) and subsequent analysis[44] identified very tight transmission security margins in New York City (Zone J) by 2034. The narrowing of the reliability margin continues to be a major concern. Most recently, NYISO's 2025 Quarter 3 STAR report[45] identified short-term reliability needs in New York City and Long Island due to generation deactivations.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

[43] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf
[44] https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf
[45] NYISO's 2025 Q3 STAR Report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf and Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

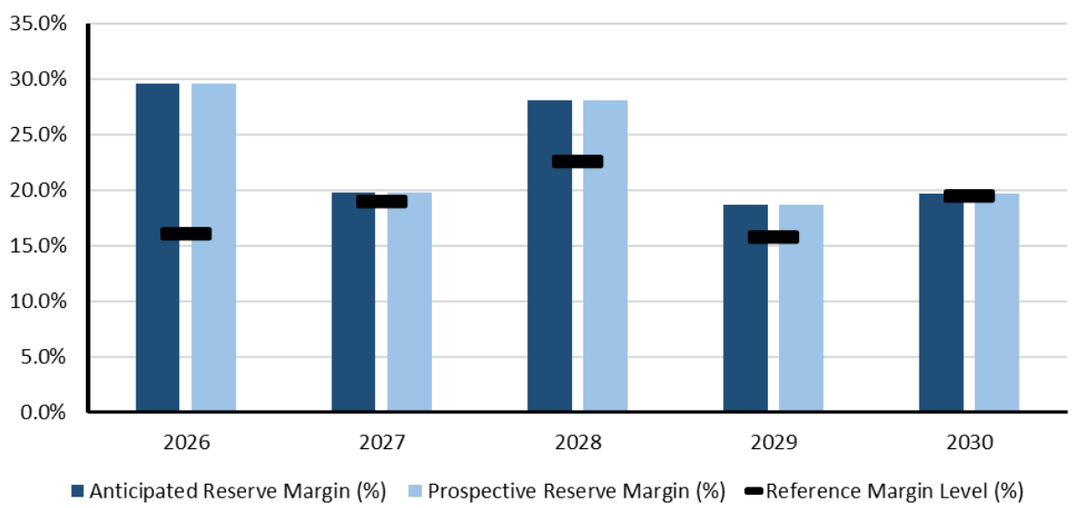


NPCC-Ontario

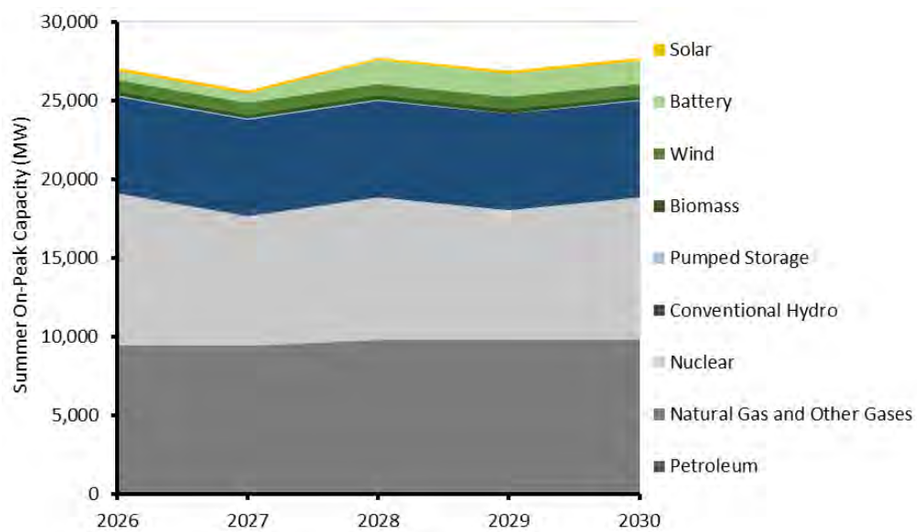
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	23,403	24,023	24,514	25,587	26,443	26,927	27,747	28,621	29,202	29,974
Demand Response	2,046	1,998	2,090	2,092	2,093	2,095	2,096	2,098	2,099	2,101
Net Internal Demand	21,357	22,025	22,424	23,495	24,350	24,832	25,651	26,523	27,103	27,873
Additions: Tier 1	853	853	2,156	2,156	2,156	2,964	3,507	4,051	4,579	5,387
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	600	600	600	1,233	1,324	1,324
Net Firm Capacity Transfers	602	772	1,002	1,002	1,432	1,002	302	302	302	302
Existing-Certain and Net Firm Transfers	26,833	25,541	26,577	25,737	26,999	25,623	25,767	25,767	26,611	26,611
Anticipated Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Prospective Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Reference Margin Level (%)	16.1%	19.0%	22.6%	15.8%	19.5%	13.9%	14.7%	9.6%	14.3%	13.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Ontario Highlights

- Ontario's ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030.
- Ontario's 2025 Annual Planning Outlook (APO) identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. Different to last year's LTRA, the IESO assumes generation resources are expected to be re-contracted (through the IESO's reacquisition mechanisms) after those contracts expire. This has improved the resource outlook for the IESO when compared to last year while aligning the methodology to forecast supply with the methodology used by other NERC assessment areas.
- For demand, Ontario projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. As a result, total internal demand is projected to grow by 31% over the next 10 years to nearly 30 GW by 2035.
- Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed procurements to re-contract existing resources.
- Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW (installed capacity) of BESS to come on-line, with discharge durations of four hours.
- Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	3	3	3	3	3
Natural Gas	9,385	9,385	9,790	9,790	9,790
Biomass	299	304	310	310	310
Solar	150	150	150	150	150
Wind	724	725	728	732	732
Conventional Hydro	6,163	6,163	6,163	6,163	6,163
Pumped Storage	38	38	38	38	38
Nuclear	9,724	8,256	9,059	8,214	9,047
Battery	597	597	1,489	1,489	1,489
Total MW	27,084	25,622	27,731	26,891	27,723

NPCC-Ontario Assessment

Planning Reserve Margins

Ontario's ARMs remain above the RML for the first five years of the *2025 LTRA* outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030. No Tier 2 resources have been identified for this year's publication.

The IESO calculates Ontario's reserve margin annually using the GE MARS model and applies a more stringent reserve criterion than the NPCC standard of 0.1 days/year LOLE, incorporating additional reserves to manage risks associated with nuclear refurbishments and new nuclear builds. For example, over the LTRA outlook, the 2025 Annual Planning Outlook (APO) includes reserves of nearly 800 MW in some summers and nearly 1,100 MW in some winters to account for uncertainties in nuclear project timelines. If these additional reserves were excluded, Ontario would meet or exceed the RML in all years of the assessment. MARS inputs include resource availability, outages, refurbishment schedules, interface limits, and demand uncertainty. The model uses probabilistic simulations and Monte Carlo analysis for wind and solar and historical data for hydro and thermal units. The assessment evaluates system adequacy across all hours, not just peak periods.

For the *2025 LTRA*, the IESO applied NERC's definitions for Tier 1 and Tier 3 resources. The IESO's Resource Adequacy Framework (RAF) enables reacquisition of existing resources nearing contract expiry. It's important to distinguish between off-contract resources and those that have reached end of life or retired. Many existing Ontario resources remain operational and can be upgraded or re-contracted, with the RAF providing competitive mechanisms to secure capacity from these resources. The *2025 LTRA* assesses reliability independent of contractual status, unlike the 2025 APO, which aims to determine the resource adequacy needs in order to inform future reacquisitions of existing and new resources. As a result, the *2025 LTRA* outlook will differ from the 2025 APO, especially regarding off-contract resources that are likely to continue to be operational.

The RAF remains unchanged since the *2024 LTRA* and continues to guide the reacquisition of existing resources and the procurement of new capacity. The RAF supports a flexible, multi-pronged approach to resource adequacy, including capacity auctions, medium- and long-term procurements, and targeted programs for re-contracting or upgrading existing facilities and securing new resources.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Ontario conducts annual energy adequacy assessments using Energy Exemplar's Plexos software, which models the province's nodal transmission network and simulates dispatch under expected system conditions. These deterministic assessments evaluate energy sufficiency over a 20-plus-year horizon and are supplemented by sensitivity analyses to identify periods of heightened risk.

The 2025 APO identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. It should be reinforced that the APO presents an energy adequacy assessment used to inform future procurements, whereas the LTRA's purpose is to inform reliability of the system, where contractual end dates are not incorporated into the assessment

Shorter-term energy assessments are conducted quarterly through the Reliability Outlook (RO), which evaluates energy adequacy over an 18-month horizon. These assessments use probabilistic demand forecasts and outage data to identify seasonal and weekly risks. While the RO time frame is too short to secure new resources, the IESO uses operational tools such as capacity auctions, coordination with market participants on outage scheduling, and DR programs to mitigate risks.

Ontario's energy adequacy assessments do not assume economic imports or exports, reflecting a self-sufficiency planning approach. However, in practice, intertie capacity and capacity-sharing agreements (e.g., with Hydro-Québec) provide additional flexibility during periods of stress.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0.043	0.001	0.066
NEUE (ppm)	0.000	0.000	0.000
LOLH (hours per Year)	0.000	0.000	0.000
***Provides the 2024 ProbA Results for Comparison**			

Demand

Ontario's demand forecast is shaped by a combination of econometric modeling for the near-term and sectoral/end-use modeling for the long term. The 2025 APO projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. Growth projections in the *2024 LTRA* were 2.34% for summer and 2.75% for winter. Marginal increases in demand growth since the 2024 LTRA are attributed to data center growth and EV production. Incremental 2025 APO forecasted growth is driven by the following:

- Electrification of buildings, transportation, and industry
- Expansion of electric vehicle (EV) production and supply chains

- Rapid development of commercial data centers
- Population growth and household formation

Offsetting factors include increased EE, DSM programs, and a plateau in agricultural greenhouse expansion.

The 2025 APO forecasted Ontario to become a dual-peaking jurisdiction by 2030, with winter and summer peaks converging due to increased electrification of heating. The IESO's demand forecast incorporates updated assumptions on immigration, economic growth, and sector-specific developments, including hydrogen production, steel decarbonization, and data center expansion. Additional large loads in planning but not yet included in the forecast are assessed based on their development stage, funding, and likelihood of materialization.

Ontario anticipates significant changes in load behavior, including increased demand from building electrification, EV charging (shifting peaks), data centers, hydrogen electrolyzers, and large industrial loads. These trends introduce variability and new reliability challenges. The IESO conducts System Impact Assessments (SIA) for large loads, evaluating impacts such as voltage flicker and transient stability. Enhancements to the assessment process are underway. Additionally, annual regulation needs assessments project up to 110 MW of incremental regulation by 2035 to manage fluctuating loads, with procurement strategies in place to meet these needs.

Demand-Side Management

The IESO has implemented a capacity qualification process that applies performance-based derates to DR resources, ensuring more reliable capacity contributions. Since the *2024 LTRA*, the Peak Perks program has expanded to small businesses, helping the program deliver more than 152 MW of summer peak demand reduction in 2024, growing to over 200 MW in 2025. A new DR program targeting HVAC loads in the commercial and institutional sector is in development. These programs, as well as the Industrial Conservation Initiative (ICI), also contribute to peak demand reduction. A new electric demand side management (eDSM) framework spanning the next 12 years commenced with a $1.8 billion budget for years 2025–2027 targeting 4.6 TWh of energy savings and 900 MW of peak demand savings.

Distributed Energy Resources

Ontario's DER landscape includes both contracted embedded generation and uncontracted BTM resources. In 2024, contracted DERs totaled over 3,400 MW, with about 60% from solar, 20% from wind, and 15% from hydro and biomass. Uncontracted DERs contributed an estimated 2.7 TWh of energy.

DERs are integrated into planning through the Enabling Resources Program (ERP), which is developing participation models for standalone DERs, hybrid resources, and aggregations. The IESO is also advancing coordination protocols through the Transmission-Distribution Coordination Working Group (TDWG), which has proposed tools for real-time coordination and visibility. The group wrapped up work during Summer 2025 and has posted final reports on their findings.

DERs are considered in transmission planning as non-wires alternatives and are increasingly included in regional planning processes. The IESO's DER Potential Study and Local Generation Program aim to further integrate DERs into Ontario's RAF.

Generation

Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. To maintain system reliability, the IESO continues to monitor key operational parameters such as primary frequency response and system inertia, both of which are currently sufficient but require reassessment as the resource mix evolves. Ramping needs can be provided by over 11,100 MW of natural gas generation with 600 MW able to be online and ramp within 20 minutes. Supply to the majority of Ontario's gas fleet is robust and supported by significant firm supply and transportation contracts. The IESO does not expect any material gas supply or delivery issues under extreme winter conditions. The day-ahead market, established through the IESO's Market Renewal's Program, allows for firm gas supply to be scheduled.

Deliverability testing is a core component of Ontario's long-term procurement process, ensuring that new resources can connect without causing congestion or reliability issues. For the IESO's second long-term procurement, testing will be expanded to include inverter-based resource screening for sub-synchronous control interactions.

Ontario has updated its Market Rules to align with IEEE 2800 and now requires synchrophasor data from generators and transmitters to improve situational awareness and IBR performance. The IESO is also conducting system-wide electromagnetic transient (EMT) studies and validating models for battery storage projects to proactively address sub-synchronous control interaction risks.

For Ontario's adequacy assessments, capacity contribution values for thermal resources are calculated using historical performance and probabilistic modeling. Wind and solar contributions are based on seasonal capacity factors, while hydroelectric values are derived from historical output. Energy storage contributions are based on a four-hour discharge duration.

Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed medium-term procurements, which re-contracted existing resources for five-year terms. In addition to medium-term procurements, the IESO also maintains mechanisms such as Reliability Must Run agreements and capacity auctions to mitigate retirement risks. The IESO is currently conducting assessments for operating reserve and frequency response for the next 10 years, intended to be included in the 2026 APO.

Overall, Ontario's generation planning is increasingly focused on flexibility, resilience, and integration of emerging technologies, with a strong emphasis on ensuring deliverability, maintaining operability, and adapting to evolving reliability challenges.

Energy Storage

Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW of new BESS to come on-line, with discharge durations of four hours. These resources were secured through the Expedited Long-Term 1 (E-LT1) and LT1 procurements.

New storage projects may also participate in the second long-term procurement and long-lead time procurement, which aim to support system reliability during periods of high demand and low renewable output, particularly in the 2029–2035 time frame.

Energy storage resources are currently modeled as generators and loads at the same location, which presents operational challenges. The IESO is working to enhance its market tools and participation models through the ERP, which includes co-located and hybrid resource integration. Storage resources are also being incorporated into resource adequacy assessments using GE MARS software, which optimizes dispatch and accounts for energy reservoir size.

While operational experience with transmission-connected storage is still limited, the IESO is actively monitoring performance and refining planning assumptions. The integration of nearly 3 GW of new storage capacity over the next four years is expected to significantly improve Ontario's ability to manage variability and meet ramping needs.

Capacity Transfers

Ontario maintains robust intertie connections with neighboring jurisdictions, including Québec, New York, Michigan, Manitoba, and Minnesota. These interconnections play a critical role in supporting reliability, particularly during peak demand periods and resource shortfalls.

Two key capacity swap agreements with Hydro-Québec provide Ontario with firm summer capacity. The 2016 agreement allows for a 500 MW swap, while the 2024 agreement enables a 600 MW per year exchange over a seven-year period. These agreements are designed to be flexible, allowing Ontario to bank capacity and use it in future summers as needed.

Ontario's planning assessments assume self-sufficiency for the purpose of reserve margin calculations. However, in practice, these intertie agreements provide a valuable reliability backstop. The IESO coordinates closely with Hydro-Québec to align assumptions and ensure deliverability across the interties.

The refurbishment of Pickering NGS as well as new small modular reactors (SMR) scheduled to come on-line in the 2030s necessitated the review of flows across the province to maintain reliable operations. As a result, several new transmission projects have been proposed.

The IESO also participates in regional and interregional transmission planning processes, including NPCC area Transmission reviews and NERC planning assessments. These reviews ensure that Ontario's transmission system can support capacity transfers and maintain reliability under a range of scenarios.

Firm capacity transfers have appeared to increase in this LTRA publication compared to 2024 due to a review of NERCs definitions, allowing modeled and coordinated capacity to be treated as firm. This process aligns with the IESO's internal studies.

Transmission

Ontario is undertaking a significant expansion of its transmission system to support growing demand, resource integration, and system reliability. Key projects include the Waasigan Transmission Line, Etobicoke Greenway, and Flow East Towards Toronto (FETT) upgrade, which will collectively enhance capacity and resilience across the province. Additional reinforcements in London, Windsor-Essex, and northeastern Ontario address regional growth and industrial development. Voltage support devices, such as shunt reactors and STATCOMs, are being deployed to manage high voltages and support new transmission lines.

Transmission planning studies have identified constrained areas, particularly in the Greater Toronto Area (GTA), Essa (Barrie area), and eastern Ontario. These constraints are being addressed through the South and Central Ontario Bulk Plan and corridor studies to secure future transmission routes.

The IESO is also planning a new 500 kV double-circuit transmission line from Bowmanville to Toronto to support the connection of SMRs at Darlington NGS. This line is expected to be in service by the early 2030s.

To streamline transmission development and integrate Tier 2 resource deliverability insights, the IESO is designing a Transmitter Selection Framework (TSF) and enhancing its evaluation of non-wires alternatives (NWA). These initiatives aim to accelerate project delivery and improve coordination among stakeholders.

Reliability Issues

Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. The IESO is actively monitoring these trends and has published technical papers to better understand their implications. SIAs are conducted for large loads to evaluate impacts on voltage, stability, and power quality, with future enhancements planned to address sub-synchronous oscillation and ramp rate concerns.

Interdependencies with critical infrastructure sectors—such as natural gas, telecommunications, and transportation—are also being assessed. Ontario's gas supply is considered robust, with most generators located near the Dawn storage hub and supported by firm contracts. Dual-fuel capabilities of some generators and coordination protocols with gas pipeline operators further mitigate risks during extreme weather. The IESO's Market Renewal Program enhances gas-electric coordination through improved day-ahead scheduling.

Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments. Emerging technologies like battery storage and SMRs also present integration challenges. To address these, Ontario's planning processes prioritize flexibility, resilience, and proactive mitigation strategies, including outage planning that accounts for extreme weather scenarios.

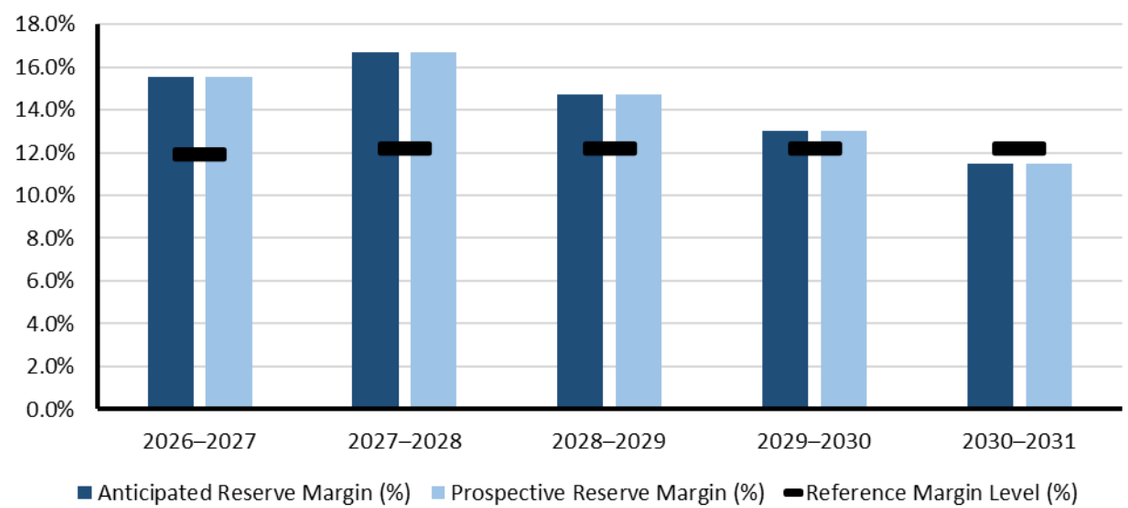


NPCC-Québec

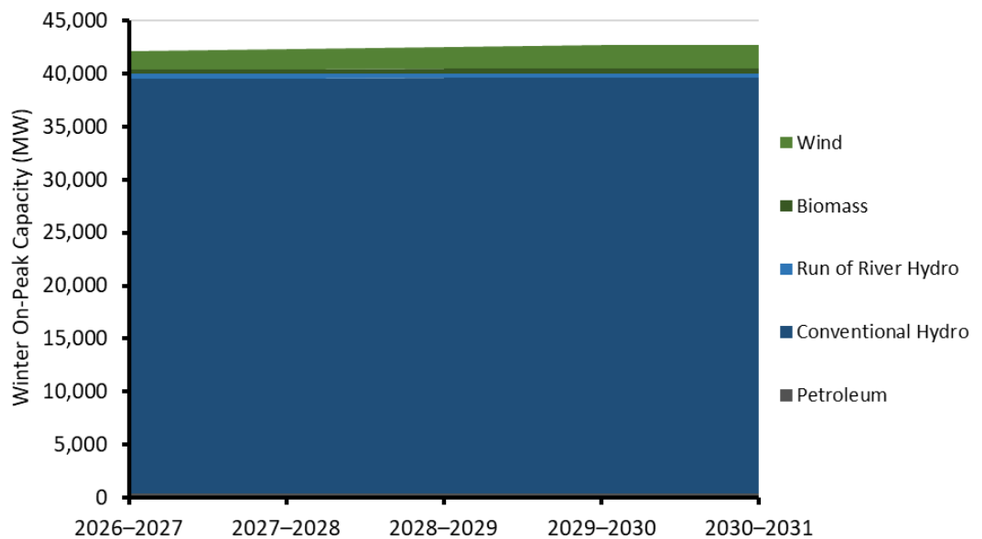
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	41,405	41,901	42,833	43,635	44,392	45,116	46,053	47,148	48,164	49,613
Demand Response	5,058	5,224	5,367	5,445	5,533	5,587	5,618	5,606	5,562	5,562
Net Internal Demand	36,347	36,677	37,465	38,191	38,859	39,529	40,435	41,542	42,602	44,051
Additions: Tier 1	412	566	710	891	891	891	891	891	891	891
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-145	455	455	455	600	0	0	0	0	0
Existing-Certain and Net Firm Transfers	41,591	42,231	42,269	42,272	42,421	41,825	41,830	41,834	41,838	41,842
Anticipated Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Prospective Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Reference Margin Level (%)	11.9%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Québec Highlights

- ARMs remain above the RML for the first four years of the assessment period.
- Over 4,000 MW of new wind installed capacity is expected to be in service by 2030, with additional wind projects in development.
- Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and gas-fired generation. These projects are not included in Tier 1–3 categories in the present assessment due to their early development stage or ongoing stakeholder consultations but are expected to be incorporated gradually into future assessments.
- Major transmission projects, including the Appalaches–Maine (NECEC) and Hertel–New York (CHPE) interconnections, are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Petroleum	429	429	429	429	429
Biomass	405	405	405	405	405
Wind[46]	1,778	1,931	2,076	2,257	2,257
Conventional Hydro	39,091	39,129	39,167	39,170	39,175
Run of River Hydro	445	447	447	447	447
Total MW	42,148	42,342	42,524	42,708	42,712

[46] Expected at-peak capacity.

NPCC-Québec Assessment

Planning Reserve Margins
ARMs remain above the RML for the first five winters of the assessment period (2025–26 to 2029–30), supported by existing and anticipated capacity and firm imports. Margins fall below the RML starting in 2030–31 due to sustained demand growth from electrification. Several large-scale projects are under development but are not included in the reserve margin calculation due to their early-stage status. The RML is based on the 2024 NPCC Interim Review of Resource Adequacy and accounts for weather and economic uncertainty, generator outages, and DR constraints.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2024 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2024, and the 2024 Québec Interim Review of Resource Adequacy filed with the NPCC in December 2024.

Over 90% of Québec's installed capacity comes from large hydroelectric reservoirs, enabling flexible and reliable energy delivery. The system is designed to withstand multi-year droughts, with planning criteria requiring sufficient reserves to cover inflow deficits of 64 TWh over two years and 98 TWh over four years. No off-peak or seasonal energy risks have been identified.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, the EUE is 62.99 MWh with an expected LOLE of 0.106 hours per year.[47]

ProbA Summary of Results			
	2026*	**2027-2028**	**2029-2030**
EUE (MWh)	8.205	0.01	62.99
NEUE (ppm)	0.040	0.000	0.29
LOLH (hours per Year)	0.014	0.000	0.11
***Provides the 2024 ProbA Results for Comparison**			

Demand
Québec's demand forecast is driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Forecasts are developed using sector-level modeling and include high and low scenarios to reflect uncertainty.

Demand-Side Management
Hydro-Québec operates a broad portfolio of DR programs, including interruptible load contracts for industrial and commercial customers, and smart heating and dynamic pricing for residential users. These programs are expected to provide 5,600 MW of peak reduction by 2034–2035. Reported capacities reflect actual observed reductions during events. EE and conservation programs are integrated into demand forecasts.

Distributed Energy Resources
BTM solar PV is expected to reach 705 MW by 2035. However, due to Québec's winter-peaking profile, the on-peak contribution of DERs remains below 5 MW. No operational impacts are expected, and no DER aggregators are currently active in the area.

Generation
4,000 MW of wind installed capacity is under development or construction, including the Apuiat project (204 MW), three 400 MW phases of Des Neiges, and two procurement rounds totaling 2,700 MW. Hydro-Québec is also pursuing:

- Up to 2,000 MW from hydro unit upgrades;
- 5,000 MW of wind installed capacity through new community partnerships;
- 3,440 MW from Churchill Falls upgrades and the Gull Island project;
- 3,000 MW of solar installed capacity by 2035, including 300 MW of front-of-the-meter PV by 2029;
- Potential battery storage and natural gas generation.

Except for the 4,000 MW of wind capacity in construction, these projects are not included in the Tier 1–3 categories due to their early development stage or ongoing stakeholder consultations.

Energy Storage
No energy storage resources are currently planned for commissioning during the assessment period.

[47] 2025 Probabilistic Assessment results cover the period from March of the first year to February of the second year.

Capacity Transfers
Québec maintains firm seasonal capacity exchange agreements with Ontario (600 MW imports in winter, exports in summer). Québec has several firm capacity export agreements during the summer season.

Transmission
Hydro-Québec plans to add 5,000 km of new transmission lines and several major substations by 2035 to support regional development and renewable integration. Key projects include the following:

- NECEC (1,200 MW to Maine) – expected in service by December 2025
- CHPE (1,250 MW to New York) – expected in service by May 2026
- Three new 735 or 315 kV corridors in Québec
- Jean-Jacques-Archambault substation – planned for 2029

No long-term transmission constraints have been identified.

Reliability Issues
Large industrial loads are screened and approved by the Québec government and Hydro-Québec based on available supply. A moratorium is in place for new blockchain clients. The system's winter peak is primarily driven by residential heating, and industrial additions are not expected to significantly affect peak uncertainty. To mitigate the impact of rising demand, Hydro-Québec is expanding its DSM programs and studying multiple new generation projects. In addition, Québec's large hydro reservoirs provide strong protection against the impacts of drought. The system is planned to meet a regulatory energy reliability criterion requiring sufficient reserves to withstand inflow deficits of 64 TWh over two years and 98 TWh over four years.

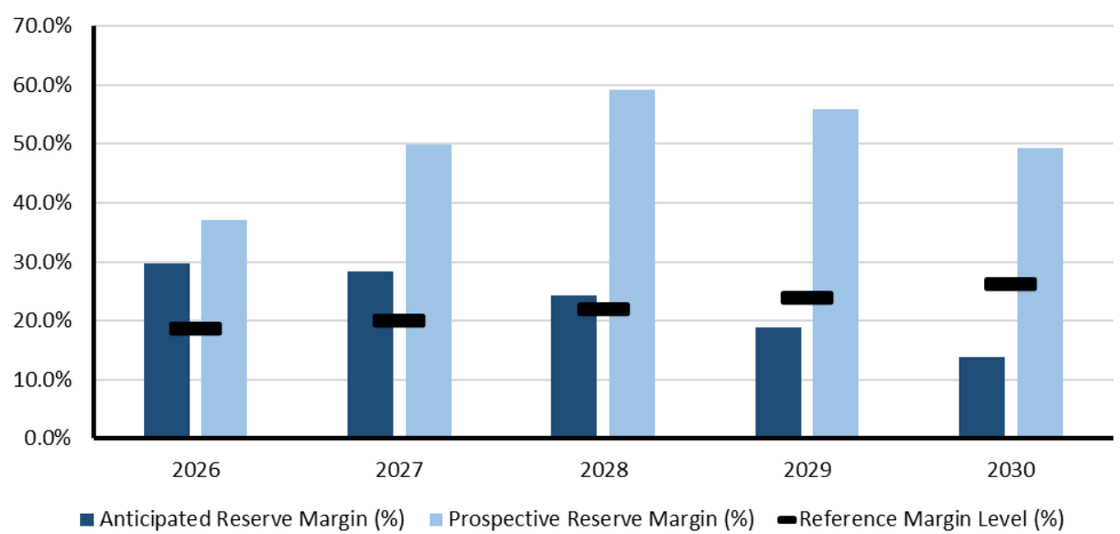


PJM

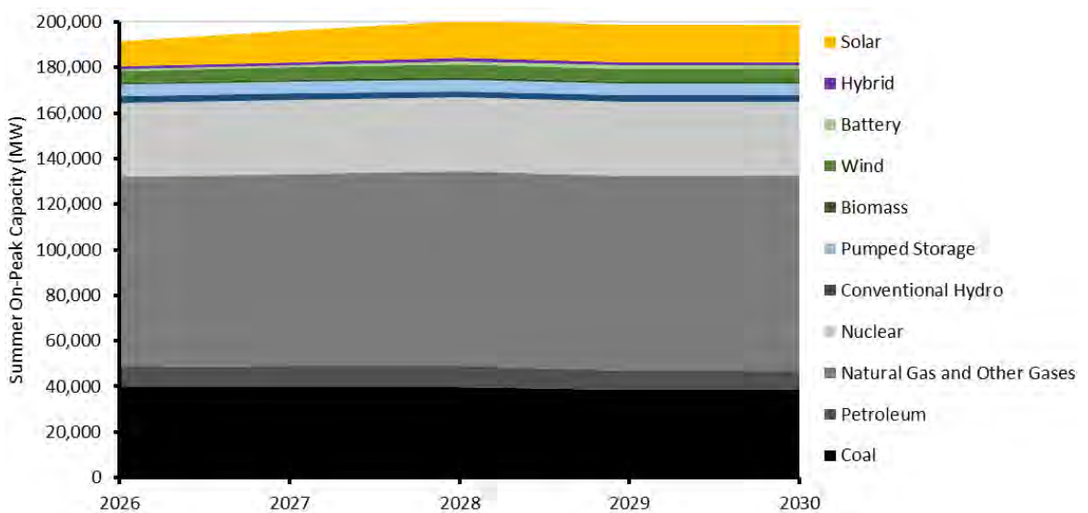
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and has an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	158,937	164,186	169,981	176,094	183,883	192,647	200,507	204,197	207,253	209,923
Demand Response	8,184	8,439	8,703	9,002	9,398	9,845	10,250	10,409	10,533	10,629
Net Internal Demand	150,753	155,747	161,278	167,092	174,485	182,802	190,257	193,788	196,720	199,294
Additions: Tier 1	5,861	10,177	14,521	14,709	14,709	14,709	14,709	14,709	14,709	14,709
Additions: Tier 2	12,410	38,519	65,315	71,119	75,116	75,290	77,655	77,655	77,655	77,655
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	3,840	3,818	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	189,693	189,644	186,005	184,030	184,030	184,030	184,030	184,030	184,030	184,030
Anticipated Reserve Margin (%)	29.7%	28.3%	24.3%	18.9%	13.9%	8.7%	4.5%	2.6%	1.0%	-0.3%
Prospective Reserve Margin (%)	37.0%	49.9%	59.1%	55.9%	49.3%	42.6%	27.7%	25.4%	23.5%	20.0%
Reference Margin Level (%)	18.6%	20.1%	21.9%	23.9%	26.3%	28.9%	30.8%	33.0%	35.1%	35.1%



Planning Reserve Margins



Existing and Tier 1 Resources

PJM Highlights

- Load forecasts have increased year over year due to data center and economic growth as well as increased electrification in the PJM footprint.
- Available generation capacity has decreased due to retirements and delays in new additions to the fleet.
- Based on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.
- PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid/minimize the need for emergency procedures.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	39,866	39,866	39,866	38,288	38,288
Coal*	39,866	37,738	27,448	28,002	26,464
Petroleum	8,952	9,163	9,163	8,766	8,766
Natural Gas	83,210	84,150	85,385	85,385	85,385
Natural Gas*	82,589	83,443	84,678	84,678	84,678
Biomass	857	907	907	907	907
Solar	11,282	13,616	16,141	16,328	16,328
Wind	5,251	5,496	5,622	5,622	5,622
Conventional Hydro	2,807	2,829	2,829	2,829	2,829
Pumped Storage	5,068	5,068	5,068	5,068	5,068
Nuclear	32,508	32,508	32,508	32,508	32,508
Hybrid	1,187	1,504	1,504	1,504	1,504
Battery	703	895	1,531	1,531	1,531
Total MW	191,712	196,002	200,524	198,737	198,737
Total MW*	191,091	193,166	187,399	187,743	186,205
***Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins
The PJM ARM falls below the Installed Reserve Requirement (RML) in 2029 when the ARM dips just below 19% as the RML reaches 24%.

- Accelerated retirements, driven by unit age and environmental public policy, of generators that provide necessary attributes needed to maintain reliability are outpacing new, mainly IBR additions. PJM received over 30 deactivation notifications totaling over 2 GW in 2024.
- Approximately 40% of new interconnection requests to the PJM grid are solar resources.

PJM faces an extreme and rapid tightening of supply and demand for capacity resources in the near term and needs additional resources to rapidly address its near-term reliability challenges.

PJM is in a transition year as the determination is based on the Reserve Requirement Study (RRS) and Effective Load Carrying Capability (ELCC) Study via PJM Manual 20A Resource Adequacy Analysis.[48]

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
Based on the load increase and generation decrease, PJM is projecting a potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.

PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid or minimize the need for such emergency procedures. The greatest risk is still during the summer peak period.

Probabilistic Assessments (NERC ProbA and Other Studies)
LOLH and EUE values for 2027 are 0.61 hours/year and 3,251 MWh/year, respectively, which are values consistent with PJM having a 2027 LOLE slightly worse than the 1 day in 10-year target. For 2029, the metrics significantly increase (LOLH = 9.97 hours/year and EUE = 67,581 MWh/year) due to significant forecasted peak load increases (i.e., more than 12,000 MW in summer and more than 14,000 MW in winter, driven by large load additions in the PJM footprint) and the changing resource portfolio mix (i.e., the retirement of thermal resources and the addition of wind, solar and storage, that do not provide an expected commensurate resource adequacy value when compared to the retired thermal resources).

In both studied years, large shares of the annual EUE and LOLH are concentrated in the winter months (especially January). In such winter days, the loss-of-load events identified by the model are driven by low temperatures, which result in high loads and the potential for high correlated outages from gas resources as well as poor performance from solar resources. These winter events tend to occur during both morning and evening peaks.

The smaller shares of EUE and LOLH observed in the summer period for 2027 and 2029 are driven by events in the evening (hours ending 19 and 20), during days with high temperature, high loads, and declining performance of BTM and front-of-the-meter solar resources, low performance of wind resources, and to a lesser extent by slightly worse performance of thermal resources.

The ProbA results differ from the LTRA results in that the ProbA models the following:

- Fewer additions: Resources that are identified as Tier 1 in the LTRA may not reach the in-service status on their targeted in-service date.
- More retirements: The current number of announced retirements does not reflect all the environmental policies that states in the PJM footprint are targeting for future years.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	538	3,251	67,580
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.11	0.61	9.97
* **Provides the 202**4 ProbA Results for Comparison			

Demand
The demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing.

PJM expects its summer peak to climb by 55,779 MW to 209,923 MW in 2035, while winter peaks are expected to grow by 62,048 MW to reach 198,175 MW by winter 2034–35.

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. Sector models also incorporate the independent assumptions on economic trends and

[48] https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf

end-use adoption and efficiency. The PJM load forecast process considers three sectors: residential, commercial, and industrial. Each sector has its own set of models and inputs.

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, load related to load adjustments (where applicable), and distributed solar generation estimates.

PJM's projected load indicators in many instances have doubled from the *2024 LTRA* projections. For example, net energy for load growth for PJM is projected to average 4.8%, up from 2.3% in last year's projections, per year over the next 10-year period and 2.9% over the next 20 years. Total PJM energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh. Annualized 10-year growth rates for individual zones range from 0.2% to 8.4% with a median of 1.6%.

Demand-Side Management

As in past years, DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during the summer peak season from 8,184 MW in 2026 to 10,629 MW in 2035. PJM's probabilistic resource adequacy modeling accounts for observed DR availability variations by season and hour.

Distributed Energy Resources

PJM expects 4,810 MW of solar DERs at the time of summer peak demand in 2030 and 5,165 MW in 2035. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM also expects 3,652 MW of contributions from plug-in EVs to load at the time of summer peak demand in 2030 and 8,250 MW in 2035, with additional contributions from distributed battery storage ranging from 300–900 MW over the same five-year period.

The net effect of DERs is included in the load forecast as the models utilize recent historical data, which implicitly include DERs.

Generation

PJM added 560 MW of new on-peak generation capacity since the 2024 LTRA. The new projects include one wind project at 24.5 MW and 19 solar projects totaling 535.5 MW. An additional 70 MW in capacity was connecting in late 2025.

Substituting thermal resources (coal, natural gas, and oil) with renewable generation (wind, solar, storage, and hybrid resources) may get significantly more challenging as the energy transition progresses and flexible thermal resources are still needed to maintain resource adequacy at one-in 10 LOLE.

Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM's ability to serve consumer demand through the energy transition. The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. Today, thermal resources supply ERSs. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built at pace, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms will be evaluated to ensure that adequate resources are incentivized to help PJM manage increasing system uncertainty and volatility.

For example, in 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative, which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. PJM projects that the initiatives will boost Tier 1 resources by an additional 8.3 GW in summer periods and 3.4 GW in winter periods from the original *2025 LTRA* data submittal.

Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. These net increases factor resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

However, many of these projects continue to be slowed or stopped by factors that extend beyond PJM and affect multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges, and financing.

PJM uses some differing capacity assumptions between the LTRA and ProbA. The LTRA counts more resource additions, mainly new solar and gas combined-cycle units, which may not actually become operational. In contrast, the ProbA is more conservative, excluding some Tier 1 resources that might not reach the in-service date as planned. Additionally, the LTRA only accounts for officially announced

retirements, while the ProbA also factors in potential retirements caused by state environmental policies, particularly affecting coal resources projected to retire by 2029.

As of June 2025, all generation capacity resources, with the exception of VERs, that are committed in PJM's Reliability Pricing Model or committed in a PJM Fixed Resource Requirement Plan shall be subject to operational testing initiated by PJM up to two times in each of the summer and winter seasons during the relevant delivery year. (Seasons are defined as: summer (May–October) and winter (November–April). Generation operational tests will be unannounced tests. The tests are being conducted to verify that generating resources can reliably operate when needed.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

There is approximately 162 GWs of solar, wind, battery and hybrid in the PJM interconnection queue requesting capacity injection rights. Hybrid resources make up approximately 20 GWs and standalone storage makes up approximately 40 GWs.

To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Currently new storage is dispatched similar to other generators in economic order. No more specific operation has been considered due to the small penetration. Many older batteries are used for regulation.

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if its transfers were dropped to zero.

Transmission

Beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated in PJM's 2024 RTEP cycle analyses for five-year (2029) and eight-year (2032) study year models. The large load increases are driving heavier, increased regional transfers and the consequent need for significant system reinforcement. PJM's load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone. Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of EVs. This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

Most transmission additions are related to local load deliverability problems and not new generation enhancement in Tier 2. Each generator is responsible for transmission enhancements associated with its interconnection and network enhancements if necessary. PJM does not use Tier 3 resources.

PJM's analysis of 2029 and 2032 summer, winter and light load conditions identified 8,520 thermal and voltage criteria flowgate violations across PJM, of which 1,609 were ineligible from competitive windows. The 6,911 remaining violations were addressed in 2024 RTEP Proposal Window No. 1

The large number of violations observed in the 2024 RTEP were driven by heavy west-to-east transmission interface flows caused by large load increases in the Dominion zone and in eastern PJM: 10 GW and 15 GW load increase for 2029 and 2032 between the load forecasts used for the 2022 and 2024 RTEP study cycles, respectively. The significant load growth is attributed primarily to data centers, electrification, and electric vehicle developments.

From PJM's 2024 RTEP Proposal Window No. 1 (July–September 2024), 94 competitive proposals to solve the 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The PJM board approved $5.9 billion worth of regional and local projects to address the reliability criteria violations.

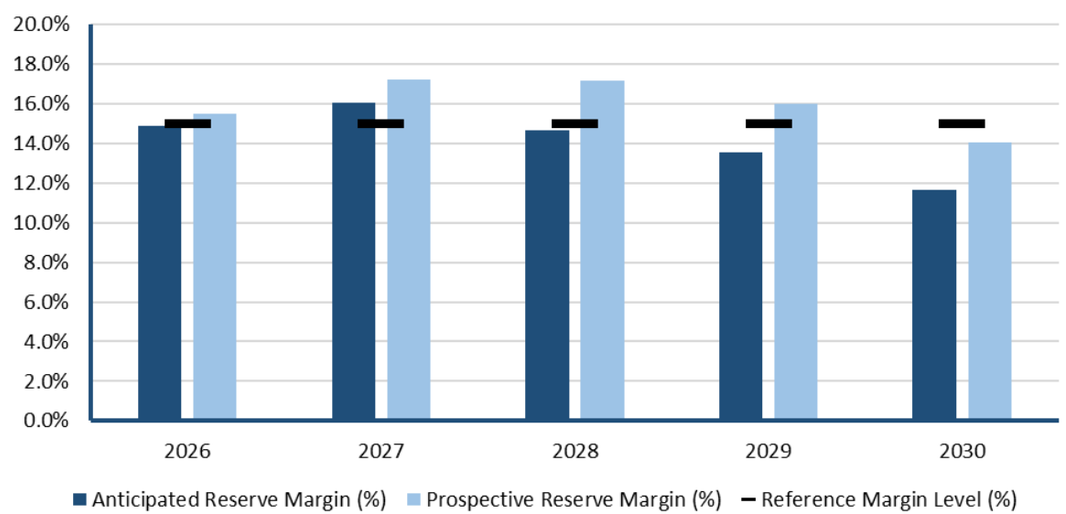


SERC-Central

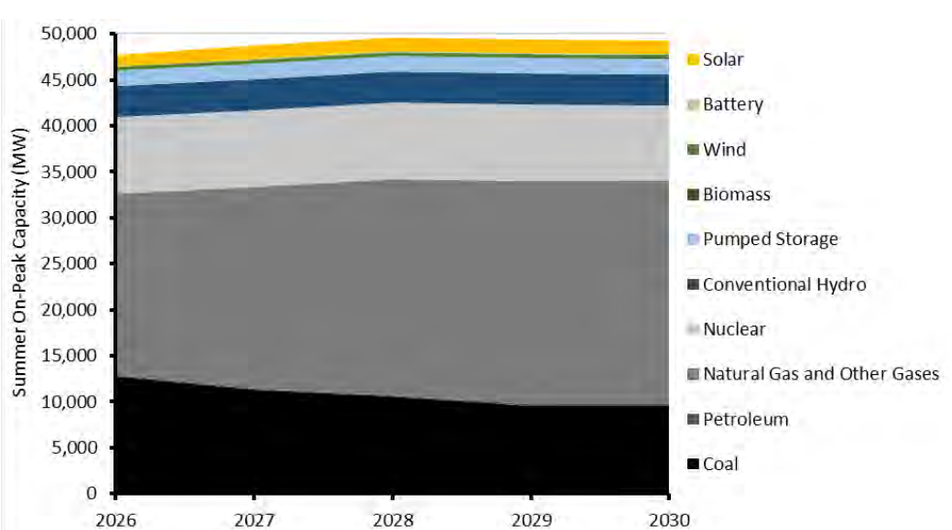
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under 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 Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	43,066	43,512	44,298	44,616	45,280	45,975	46,034	46,168	46,412	46,619
Demand Response	2,818	3,047	3,287	3,356	3,364	3,377	3,392	3,367	3,323	3,301
Net Internal Demand	40,248	40,465	41,011	41,260	41,916	42,598	42,642	42,801	43,089	43,317
Additions: Tier 1	518	492	4,567	5,435	5,435	5,435	5,435	5,435	5,435	5,735
Additions: Tier 2	20	245	837	837	837	837	837	837	837	837
Additions: Tier 3	178	234	300	362	743	795	2,107	3,293	5,539	5,591
Net Firm Capacity Transfers	460	391	-288	-287	-287	-221	-221	-220	-220	-157
Existing-Certain and Net Firm Transfers	47,859	47,438	45,895	44,503	43,474	43,382	43,448	42,484	42,485	41,414
Anticipated Reserve Margin (%)	19.1%	20.8%	19.7%	18.5%	16.5%	14.8%	12.4%	12.0%	8.7%	9.0%
Prospective Reserve Margin (%)	19.7%	22.0%	22.3%	21.1%	19.0%	17.3%	14.9%	14.5%	11.2%	11.5%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Central Highlights

- SERC-Central is projected to remain above its RML through 2030. The ProbA shows no loss of load over the 2027 and 2029 study years.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	12,782	11,308	10,595	9,565	9,565
Coal*	**12,782**	**11,308**	**9,944**	**8,914**	**8,914**
Petroleum	128	128	128	128	128
Natural Gas	19,706	21,956	23,483	24,341	24,249
Natural Gas*	**19,279**	**21,529**	**22,585**	**23,443**	**23,443**
Biomass	37	37	37	37	37
Solar	1,181	1,408	1,445	1,455	1,455
Wind	370	370	370	370	370
Conventional Hydro	3,405	3,405	3,405	3,405	3,405
Pumped Storage	1,247	1,247	1,247	1,247	1,247
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	100	135	135	135	135
Total MW	47,236	48,274	49,124	48,963	48,871
Total MW*	**47,256**	**48,267**	**47,996**	**47,835**	**47,835**
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins

PRMs are crucial for ensuring the reliability and adequacy of electric transmission systems in the Central assessment area, with various entities employing different methodologies and targets. The concept of LOLE, often aiming for a standard of one day in 10 years (0.1 LOLE annually), is a critical metric used to establish these targets.

Several entities establish reserve margin levels based on resource adequacy study results. For instance, one entity sets target reserve margins at 29% in winter and 23% in summer, determined using a 1-in-10 LOLE study, a change from its previous economic reserve margin approach, which resulted in lower targets. Another entity performs a reserve margin study using the Astrapé Strategic Energy and Risk Valuation Model (SERVM) to establish summer (18%) and winter (25%) planning targets, balancing seasonal risk and cost, which also aligns with a 1-in-10-year expected probability of a loss-of-load event. Another entity uses the NERC/SERC-accepted 15% reserve margin for predominantly thermal systems, which is generally consistent with a one-day-in-10-year loss of load. Methodologies for determining these margins often involve probabilistic modeling using extensive weather data (e.g., 40 years of weather data with Astrapé SERVM) and simulations of hourly forced outages, load, market availability, and renewable resources. Key drivers of risk often include extreme weather, low renewable generation, forced outages, and limited import capability.

Since the *2024 LTRA*, some significant changes have occurred or are underway. One entity recently updated its minimum reserve margin constraints from economic reserve margin targets to a resource adequacy standard of one day in 10 years LOLE. This entity also conducted a LOLE study that incorporated improvements such as enhanced peak demand modeling and additional sensitivities, including temperature-dependent outage probabilities. Load forecasting is also updated annually to meet NERC MOD-32 requirements, aiming to maintain reserve margins at minimal cost while balancing risk, reliability, environmental responsibility, and flexibility.

Currently, most entities' ARMs are not expected to fall below their RMLs. However, challenges stemming from load growth and increased load sensitivity to weather, particularly in winter, have led to a reduction in reserve margin levels over the next 10 years for some. To address potential shortfalls and future needs, resource additions are being planned, including solar facilities, natural gas combined-cycle units, and battery storage. Utilities also account for uncertainty and variability in assumptions through quantitative scenario modeling and probabilistic weighting of key assumptions. The results of energy risk assessments are used to establish or confirm PRM targets based on simulations and scenario analyses, which account for variability in load, weather, and unit outages to ensure system reliability.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Energy risk assessments are an evolving aspect of grid reliability planning, moving beyond traditional peak-demand analyses to encompass all potential hours of the year, including non-peak periods in the Central subregion. These comprehensive assessments are vital due to the increasing variability and uncertainty in system demand and resource mix. Utilities employ a range of methods for these assessments, often including detailed LOLE studies that simulate hourly conditions over a 10-year horizon, incorporating extensive historical weather data and system flexibility. Some entities adopt a holistic, year-round planning approach that integrates scenario-based reserve margin analysis and robust fuel inventory management to handle supply and demand uncertainties. Probabilistic modeling is commonly used, leveraging extensive weather data (e.g., 40 years of weather data), and simulating hourly forced outages, load, market availability, and renewable resources to identify risks across a wide range of conditions.

Key drivers of risk examined in these assessments include extreme weather (both highly unexpected demand impacts and unseasonable conditions), low renewable generation, forced outages, and limited import capability. Other factors considered are low water conditions, fuel availability (such as natural gas pipelines and their interdependencies), resource outages, transmission constraints, common mode failures, correlated and dependent outages (derations), ramping limitations, and flexibility requirements. The results of these energy risk assessments are directly used to establish or confirm PRM targets, which are designed to account for variability in load, weather, and unit outages to ensure overall system reliability. These assessments also emphasize the importance of a balanced and diversified generation portfolio to reduce dependency on single sources and to hedge against supply disruptions. Furthermore, they support detailed operational planning, such as maintaining higher reserve margins during shoulder months to mitigate risks from maintenance outages and unpredictable weather, and implementing fuel security measures like firm transportation contracts and fuel inventory targets. Ultimately, the outcomes of energy assessments inform and guide a broad spectrum of strategic, operational, and planning decisions, ensuring that utilities can build robust, adaptive plans to provide consistent and reliable service despite external uncertainties and the evolving conditions of the electricity system.

ProbA Results

In the SERC model, based on data and assumptions, SERC-Central does not show any loss of load risk for 2027 nor 2029 for any of the 5375 cases. The annual metrics are shown below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0.10	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*Provides the 2024 ProbA Results for Comparison			

However, the study shows overall reliance on imports from neighboring areas with the potential of insufficient local generation to meet the demand. The month of April in particular shows the risk of low hydro generation, which can coincide with planned maintenance outages. The summer load forecast is expected to grow by 1,005 MW and winter load forecast is expected to grow by 781 MW from 2027 to 2029. At the same time, there is an expected retirement of approximately coal generation in 2028, leading to tighter margins. Close to 2,600 MW of gas generation is expected to be added in the same period. Based on the ProbA, overall margins get tighter in 2029.

Demand growth, planned generator retirements, fuel diversity and reliance on imports contribute to growing energy risks. SERC and the SERC Central entities will need to continue to monitor the resource adequacy studies.

Demand

Utilities in the Central assessment area employ comprehensive and evolving methodologies to project future energy and demand needs, crucial for accurate system planning. Load forecasts are regularly updated, typically every one to two years, drawing heavily on historical data including hourly load profiles, economic indicators, demographic trends, and weather patterns. Many entities utilize econometric or regression-based models to capture the relationship between energy usage and variables like temperature, population, and housing. To account for uncertainty and variability, some utilities develop multiple forecast scenarios, employing historical weather extremes or probabilistic modeling to capture a range of potential outcomes. Forecasts also integrate emerging factors such as DERs, EVs, and end-use efficiency trends. Advanced modeling techniques include shaping system forecasts with hourly load profiles by customer class and DER type, with adjustments for anticipated industrial or commercial growth. Load forecast uncertainty (LFU) is managed through both quantitative scenario modeling and probabilistic weighting of key assumptions. Forecasts beyond a 10-year horizon, while highly uncertain, provide insights into potential long-term drivers such as the addition of data centers and large commercial/industrial loads, which can substantially increase demand and are often modeled as sensitivities in reliability studies. Electrification trends, particularly in home heating, contribute to increased winter peak sensitivity, and transportation electrification is expected to become a more significant driver beyond the 10-year horizon. While climate change and extreme weather impacts often are not pronounced in probabilistic load models, some models are refined to reflect more frequent cold weather patterns, and load impacts are often addressed through scenario planning rather than directly embedded in long-range forecasts.

Demand-Side Management

DR and other DSM programs vary significantly across utilities in the Central assessment area, playing a role in managing demand and enhancing system flexibility. Some entities model their DR programs as dispatchable supply-side resources, meaning their contribution is not reflected as load reductions in forecasts, with available capacity often estimated based on historical performance and being highly weather-dependent. Plans are in place for significant expansion of DR capacity over the next five years by some entities. Specific programs include legacy Interruptible Power, the newer PowerFlex offering greater flexibility in response times, and the relaunched dispatchable voltage regulation (DVR) program, which provides enhanced credits for both emergency and capacity events. Conservation voltage reduction (CVR) is employed as a 24/7 energy-efficiency tool, and Peak Rewards is an aggregator-based DR program for large commercial and industrial customers. Capacity from these programs is estimated based on historical reactivity to voltage changes and forecasted load, with some having specific use limitations, such as 400 event hours per year for DVR. While some smaller entities in Central report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, other entities are actively growing this resource class, particularly for DR and peak load management. These aggregator-based programs are included in IRP inputs and modeled through semi-annually updated Power Supply Plan processes. The development and refinement of these programs help utilities ensure consistent and reliable service by balancing supply and demand, especially during critical periods.

Distributed Energy Resources

DERs, primarily solar PV, are generally incorporated into net load forecasts by most entities within the Central assessment area, though the specific methodologies and extent of integration vary. Some entities utilize historical data and national laboratory research to integrate distributed generation and EVs into their peak demand and energy forecasts. For example, one entity projects solar PV to reach approximately 1% of summer peak demand by 2028, with total DER capacity anticipated to be 153 MW by 2032. Another entity, which incorporates both BTM and front-of-meter DERs, forecasts solar PV penetration to grow from 250 MW by 2029 to 350 MW by 2034. They model BTM resources using irradiance-based hourly shapes and treat program-based solar as a fixed energy supply with simulated profiles. Future DER growth is projected using adoption curves based on economic payback periods and market trends, also accounting for local self-generation programs that allow up to 5% of annual energy needs.

However, some entities in the region either do not currently utilize or separately account for DERs due to minimal penetration or a lack of utility-sponsored programs. One entity has implemented a

cap on DER penetration at 10% of peak demand, expecting to reach this limit within five years, and models DERs at 80% of capacity during system peaks. IBRs, which include many DERs, are subject to rigorous modeling and verification processes, including fault ride-through testing, oscillation monitoring, and the enforcement of a minimum short-circuit ratio (SCR) to maintain system reliability.

The contribution of DER aggregators is currently limited but is actively expanding in the assessment area, with select entities integrating them into planning and demand-side management strategies. These aggregator-based programs are included in the entity's Integrated Resource Plan (IRP) inputs and are modeled through its semi-annually updated Power Supply Plan process. While some smaller entities report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, others with minimal DER participation do not account for them separately in resource planning. The capacity from DER aggregators, where applicable, is generally reflected as part of DR resources and modeled as dispatchable or embedded in the net load forecast, depending on the entity. Overall, the assessment area sees a proactive effort by leading entities to grow this resource class for DR and peak load management as the energy landscape evolves.

Generation

Utilities in the Central assessment area are actively engaged in managing their generation portfolios, which are undergoing significant transformation, primarily driven by the integration of IBRs and a focus on flexible, dispatchable capacity. Planning entities have mechanisms to prevent the retirement of reliability-critical units, such as state laws mandating replacement with dispatchable capacity or ensuring replacement generation is established before retirement. Reliability and reserve margin studies are used to assess the impacts of retirements. One entity maintains its plan to retire a 297 MW coal-fired unit in 2027 due to economic and environmental factors, though the timing is under reassessment. There have been no changes to confirmed or unconfirmed retirements since the *2024 LTRA*, with entities projecting no new retirements.

Changing Resource Mix and Operational Considerations: Entities are addressing potential operational issues stemming from this evolving resource mix, particularly due to the increased penetration of solar, BESS, natural gas, and hydro resources. For instance, one entity is retiring a 297 MW coal-fired unit and adding approximately 240 MW of utility-owned solar, a 645 MW natural gas combined-cycle (NGCC) unit, and a 125 MW battery storage facility to enhance system ramping flexibility and absorb more intermittent generation. While annual stability assessments generally show no transmission stability issues, some entities have observed operational challenges related to IBR controls, tuning, and power oscillations. To mitigate these, advanced testing and commissioning processes for new IBRs are being implemented, including a "burn-in" period, and utilities require utility-scale solar resources to operate on automatic generation control (AGC) and allow for automated, proportional output reductions during surplus conditions. Planning activities regularly assess system inertia with IBRs, finding no critical issues related to low system inertia so far.

Addressing Net Demand Ramping Needs: Planners are proactively ensuring sufficient flexible resources are available for long-term net demand ramping needs. Some entities maintain a diverse mix of flexible, dispatchable resources with no planned thermal asset retirements, ensuring adequate inertia and system stability. One larger entity is preparing for the potential integration of up to 11,000 MW of solar over the next 15 years. Proactive measures include replacing 1,400 MW of aging combustion turbines (CTs) with 1,500 MW of modern Frame-type CTs, refurbishing older peakers, and planning for at least 500 MW of new aeroderivative CTs to support flexibility. Exploration of **long-duration energy storage technologies**, such as pumped hydro, gravity-based systems, and flow batteries, is also underway to provide future flexibility. A contractual ability to curtail solar output during times of low demand and high solar output, particularly in spring, serves as a backup measure.

Capacity Contribution Values for Various Resources: Capacity contribution values for different generation types vary based on resource characteristics and available data:

- **Thermal resources** typically use historical performance data, with planned additions relying on vendor guarantees. Forced outage rates for thermal units are generally not reflected in the reported values.
- **VERs** like wind and solar utilize seasonal or monthly net dependable capacity (NDC) values based on historical performance or modeled solar irradiance at peak times. For example, one entity uses 84% of nameplate capacity for solar in summer and 0% in winter, while another uses a 50% confidence level for monthly wind and solar contributions, accounting for inverter risk.
- **Energy storage** contributions vary by duration and reliability benefit; one entity assigns 93% for 8-hour storage and 85% for 4-hour storage, considering 4-hour duration sufficient for reliability.
- **Hydroelectric resources** are evaluated using historical seasonal performance. Most methodologies have remained consistent since the previous LTRA, with updates primarily to assumptions for loads, outages, and transmission imports. Probabilistic modeling, such as ELCC, is used to ensure resource adequacy.

IBR Performance and Reliability: Entities are actively addressing reliability risks from IBRs through various study requirements and operational protocols. Some require EMT models as part of the interconnection study process. Rigorous modeling and validation practices are implemented, including mandating PSSE and PSCAD models for interconnection, enforcing quality control, and evaluating harmonic distortion. A key focus is on inverter control systems that prevent momentary cessation and ensure inverters remain on-line during voltage and frequency excursions. While no

protection schemes or ancillary service needs have explicitly emerged, increased regulation demand has been observed with growing IBR penetration. AGC capability is being mandated for all new utility-scale solar facilities, and legacy plants are being retrofitted to allow system-wide output reductions for flexibility during surplus generation events. The primary challenges with IBRs relate to system stability and control rather than resource adequacy.

Generator Retirements

Natural Gas Fuel Supply Risk: Natural gas fuel supply risk is mitigated through various strategies, including **on-site fuel oil backup** at key generation sites and contingency-based studies simulating pipeline disruptions. One entity estimates that approximately **87% of its gas-fired winter peak capacity will have firm gas transportation or fuel oil backup** within the next five years. Following a 2022 winter event, reliability improvements were implemented by an affected pipeline operator. Strategies also include 100% storage-backed firm transportation for combined cycle units, diverse procurement and scheduling, and embedding fuels personnel in system operations for real-time communication with pipeline operators during contingency events. Long-term planning considers natural gas infrastructure limitations when evaluating new generation resource locations, ensuring fuel supply adequacy and construction timelines.

Energy Storage

Energy storage, primarily BESS, is being added to the system and is expected to contribute to reliability and flexibility. Expected uses include economic operation, reliability enhancements, peak shaving, and frequency response. The capacity contribution of energy storage is factored in based on its supply duration, with entities considering different minimum durations (e.g., 4-hour or 8-hour discharge capability). One entity is adding a 125 MW battery storage facility. These resources are incorporated into long-term planning through IRPs and power supply processes.

Capacity Transfers

The Central assessment area is proactively managing capacity transfers and ensuring transmission adequacy through a variety of studies, strategic investments, and coordinated efforts to maintain system reliability amidst an evolving resource mix and load growth.

The assessment area's ability to transfer capacity is continuously evaluated and is evolving:

- **Evaluation Methods:** Transfer capabilities are assessed through biennial resource adequacy studies that account for firm contracts and probabilistic delivery expectations, showing a positive contribution from increased firm contractual capacity to overall reliability. Seasonal assessments are also conducted to identify surplus transfer capacity across different times of the year, allowing for more accurate planning of bidirectional flows and optimizing the scheduling and delivery of transfers.
- **Observed Impacts and Trends:** One entity has seen an increased reliance on external generation resources, with over 6% of its firm capacity sourced from outside its immediate footprint, driven by fossil unit retirements, load growth, and shifts in its generation portfolio. While no significant changes in power flow patterns have been identified overall, the ongoing transition in the resource mix, along with planned retirements and new additions, is anticipated to influence future transfer scheduling, surplus availability, and bi-directional flow characteristics.
- **Coordinated Efforts:** Entities are implementing various coordination efforts to ensure reliable capacity transfers:
- **Seasonal Capacity Transfer Studies** analyze how different system conditions (e.g., summer and winter peaks, shoulder months) impact import/export capabilities.
  - A transfer monitoring process tracks firm capacity from external generators, ensuring their reliable availability during peak conditions.
  - Coordination with neighboring balancing authorities is undertaken to secure contractual commitments and physical transfer capability.
  - Some entities embed transfer analysis into their long-term planning documents (e.g., IRPs) to evaluate how future firm transfers impact transmission constraints and local reliability.

Transmission

Entities in Central are maintaining transmission adequacy, with significant projects and planning processes in place to address limitations and ensure reliability.

- **Major Transmission Projects:** The assessment area is undertaking numerous projects to support reliability and accommodate changing load and generation patterns. These include the following:
  - **New Line Construction:** Approximately 158 miles of new 345 kV lines and 18 miles of 161 kV lines, along with new 56 MVA 161/69 kV stations
  - **Substation Construction and Expansion:** Three new 345/161 kV stations and one new 161 kV switching station
  - **Transformer Additions/Upgrades:** Various upgrades to 345/161 kV and 161/69 kV transformers to increase capacity
  - **Line Rebuilds and Voltage Conversions:** Over 227 miles of 161 kV lines are being rebuilt, and nearly 20 miles of 69 kV lines are being converted to 161 kV

- **Voltage and Stability Projects:** Installation of a 60 MVAR capacitor bank (by 2025) and planned Statcoms to address voltage reliability
- **Regional Reinforcements:** Projects like a new 161 kV Line and Apalachia Area Improvements are critical to mitigate thermal overload, voltage collapse, and support native load reliability

- **Identified Transmission Limitations:** Planning studies have identified constraints often associated with transformer overloads, line loading issues, or high-voltage conditions.
- **Mitigation Planning and Actions:** To address identified limitations, utilities employ the following:
  - **Operating Guides and Real-Time Controls:** Providing generation dispatch limits or specific switching actions for constrained locations
  - **Infrastructure Expansion:** Planning multiple long-term system reinforcements
  - **Congestion Management Processes:** Using system operator tools and protocols to re-dispatch generation or adjust flows
  - **Annual Transmission Assessments:** Identifying and addressing long-term transmission constraints, including new service requests and interconnections
- **Changes to Transmission Planning Processes:** Since the 2024 LTRA, several enhancements are being implemented or considered:
  - Expanding the biennial Long-Range Plan to incorporate power transfers and extreme weather events
  - Updating generator interconnection and affected system procedures to comply with FERC Order No. 2023, with one entity transitioning to a cluster study approach (transitional cluster in 2025, full cluster in January 2026) to streamline interconnection requests and reduce backlogs
  - Evaluating multi-value projects through resource and capacity assessments to proactively address long-term transmission needs

Reliability Issues

The Central assessment area is actively managing and addressing a range of reliability issues stemming from evolving system conditions, including changes in resource mix, load growth, and extreme weather.

- **Reduced Reserve Margins and Challenges from Load Growth:** Entities in the SERC-Central region are confronting challenges due to load growth and an increased sensitivity of load to weather, especially in winter, which has resulted in a reduction in reserve margin levels over the next 10 years. While some entities anticipate their ARMs will not fall below their RMLs, one entity projects that without replacement resources, its reserve margin would fall below its target range due to a unit retirement in 2027, necessitating further resource additions for increasing economic development load beyond 2027. Underlying reliability issues include increasing winter peak demand sensitivity to weather and the potential for new large commercial loads. To address this, resource additions are being planned, and some entities are shifting their minimum reserve margin constraints to a resource adequacy standard of one day in 10 years LOLE, moving away from prior economic reserve margin targets that resulted in lower targets. Large industrial or commercial load additions, such as data centers and manufacturing centers, are actively monitored as they can introduce reliability risks due to short lead times and uncertain scalability, potentially challenging load forecasting and transmission development.
- **Operational Issues and System Stability with the Changing Resource Mix, Particularly IBRs:** The assessment area is actively addressing potential operational issues stemming from the increasing integration of IBRs like solar and BESS. Some entities have experienced operational challenges related to IBR controls, tuning, and power oscillations, including instances where solar generation contributed to over-generation events. While annual stability assessments have not yet identified transmission stability issues or critical issues related to low system inertia, increased regulation demand has been observed with growing IBR penetration. To manage these risks, entities are implementing proactive measures such as advanced testing and commissioning processes for new IBRs, requiring them to demonstrate stable performance. New utility-scale solar facilities are being mandated to operate on AGC, and legacy plants are being retrofitted for system-wide output reductions to provide flexibility during surplus generation events. The primary challenges related to inverter risks in the assessment area are system stability and control, rather than resource adequacy.
- **Natural Gas Fuel Supply Risk:** The reliability of the BPS faces risks from natural gas generator fuel supply issues, including production or transportation curtailments and limitations during both normal and extreme weather conditions. To mitigate these risks, various strategies have been developed.

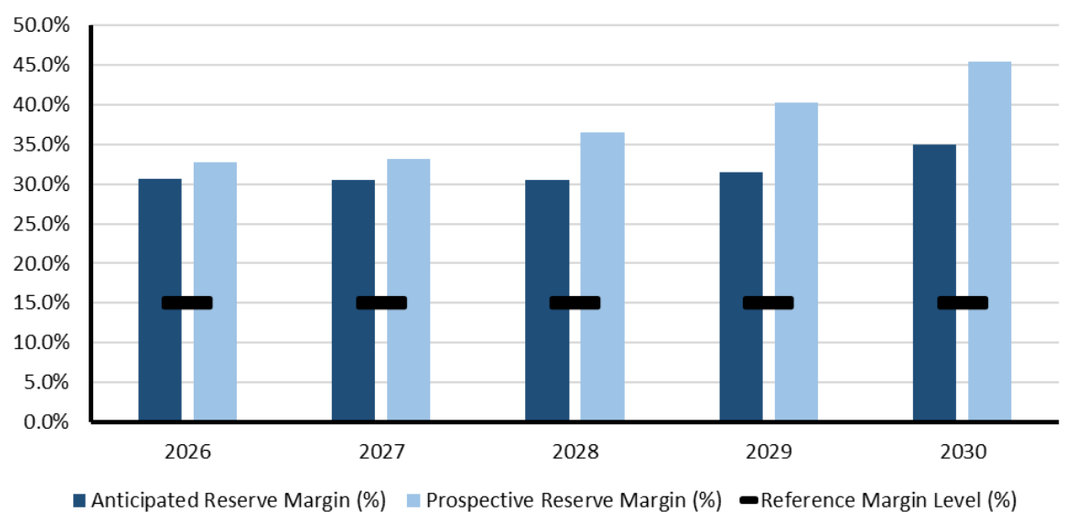


SERC-East

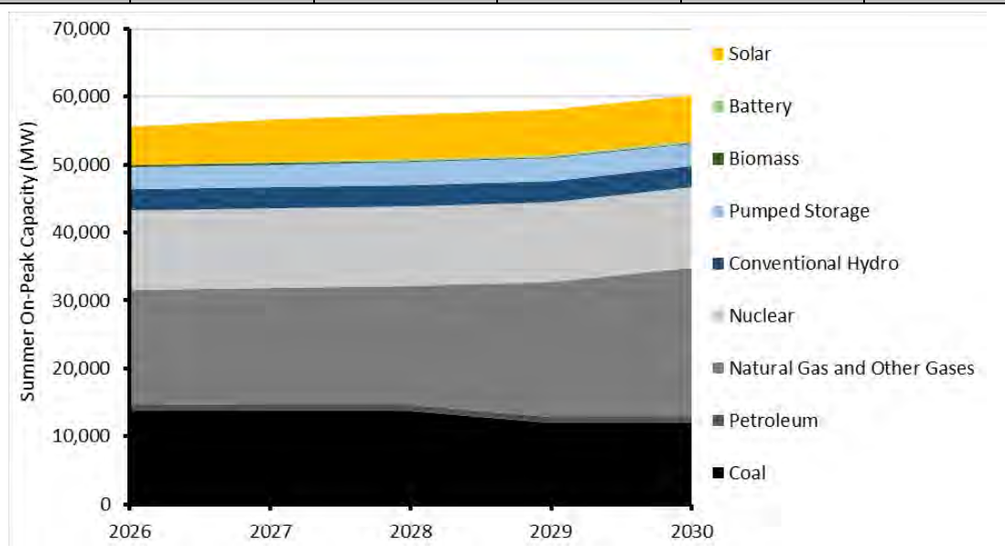
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible 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 Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	44,414	45,289	45,893	46,128	46,646	47,256	47,776	48,445	48,870	49,313
Demand Response	1,608	1,620	1,621	1,652	1,679	1,702	1,726	1,751	1,773	1,795
Net Internal Demand	42,806	43,669	44,272	44,476	44,967	45,554	46,050	46,694	47,097	47,518
Additions: Tier 1	959	2,109	2,817	5,282	7,348	8,656	9,921	11,186	11,186	11,186
Additions: Tier 2	215	484	2,009	3,231	4,045	4,551	5,114	6,232	9,022	9,022
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	150	150	150	236	236	236	236	236	236	236
Existing-Certain and Net Firm Transfers	54,964	54,880	54,953	53,222	53,316	52,237	50,919	50,919	49,557	49,557
Anticipated Reserve Margin (%)	30.6%	30.5%	30.5%	31.5%	34.9%	33.7%	32.1%	33.0%	29.0%	27.8%
Prospective Reserve Margin (%)	32.7%	33.1%	36.5%	40.3%	45.4%	45.1%	44.7%	47.8%	49.5%	48.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-East Highlights

- The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years.
- To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	13,715	13,715	13,715	11,898	11,898
Petroleum	1,044	992	992	992	992
Petroleum*	1,044	868	868	868	868
Natural Gas	16,737	17,081	17,396	19,816	21,851
Biomass	176	176	176	176	176
Solar	5,649	6,223	6,626	6,671	6,702
Conventional Hydro	3,094	3,094	3,094	3,094	3,094
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,808	11,808	11,902
Battery	8	208	258	258	258
Total MW	**55,540**	**56,606**	**57,388**	**58,035**	**60,196**
Total MW*	**55,540**	**56,482**	**57,264**	**57,911**	**60,072**
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins

PRMs in the assessment area are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. However, there are variations among entities. For instance, one generation-only BA with an all-hydro portfolio finds reserve margin requirements inapplicable, while another entity reports sufficient margins. A third entity anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and its targeted 18% winter reserve margin. To address this, it has issued requests for proposals for new capacity resources, including battery energy storage, and is evaluating longer-term options.

Other entities expect their reserve margins to remain above the 15% reference level for both near-term (0–5 years) and longer-term (6–10 years) outlooks, despite significant projected winter load growth of approximately 2% annually, which is expected to increase winter peak demand by about 6,500 MW by 2035. Their IRPs identify substantial new resources through 2035, including thousands of megawatts of solar, battery storage, wind, combustion turbines, combined-cycle units, and small modular nuclear reactors. They also plan to implement uprates to existing units. These entities aim to achieve a 22% winter PRM by 2031. Approximately 5,800 MW of coal generation is slated for retirement over the next decade, but these retirements are contingent on securing sufficient replacement capacity to maintain reliability and meet the 22% winter reserve margin target. Without firm replacement resources, coal retirements would be deferred to preserve system reliability.

Since the *2024 LTRA*, most entities have not significantly changed their resource adequacy planning or procurement processes. One entity, operating hydro-only resources, has not made any changes, nor has another entity that is replacing coal-fired generation with natural gas combined-cycle units, though this shift indirectly enhances reliability. However, a third entity, based on its 2022 LOLE study, increased its winter reference PRM from 12% to 18% by 2026, while maintaining the summer reserve margin at 15%. This adjustment reflects heightened concern over winter reliability risks due to electrification trends and potential load increases. Other companies continue to refine strategies for load growth, resource additions, unit uprates, and retirements, maintaining an "all-of-the-above" strategy.

The RML is typically determined by each entity using probabilistic reliability metrics, commonly targeting a LOLE of no more than 1 day in 10 years, or to comply with state requirements. Entities establish separate summer and winter RMLs, considering factors such as load forecast uncertainty, generator availability, and extreme weather impacts. Planning relies on detailed statistical modeling and ELCC studies to assess resource contributions, particularly for variable energy resources like solar, batteries, and wind. The capacity contribution values for variable energy resources and energy storage are determined by ELCC analyses, which discount nameplate capacity to firm, dependable capacity to meet LOLE standards, while non-variable resources like thermal units are counted at their nameplate capacity. Uncertainty and variability in assumptions are accounted for through "High" and "Low" load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, which in turn drive planning reserve and resource-adequacy sensitivity cases. Although no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources. A reliability verification step within the IRP process ensures that any developed portfolio meets reliability criteria, regardless of its stated installed capacity (ICAP) margin.

Energy Risk, Probabilistic-Based Assessments

Entities within the assessment area exhibit varying approaches to assessing energy risk, with some currently in the early stages of implementation or lacking formal processes. For instance, one generation-only BA with an all-hydro portfolio has not identified any energy risks to date. Another entity has yet to establish a formal energy risk assessment process but is preparing for the forthcoming implementation of NERC's BAL-007-1 standard, which will mandate the development of such procedures and assessments. A third entity also acknowledges the importance of developing these capabilities but currently has no established process or results to report.

Despite the current limitations in formal assessments, the sources indicate that key drivers of energy risk expected to be considered in future evaluations include the following:

- Fuel availability constraints, particularly concerning natural gas supply and delivery
- Impacts from unseasonable extreme weather
- Limitations of variable energy resources
- Transmission or interchange constraints
- Correlated outages
- Other factors such as low water conditions, resource outages, and ramping limitations

Entities within the assessment area extensively employ probabilistic reliability metrics and studies as fundamental tools in their transmission and resource planning processes. These assessments are primarily centered on determining resource adequacy and PRMs, with a common objective of achieving a LOLE of no more than 1 day in 10 years. This probabilistic standard is a cornerstone for establishing the reliability needed to meet anticipated demand.

Key probabilistic assessments and their applications include the following:

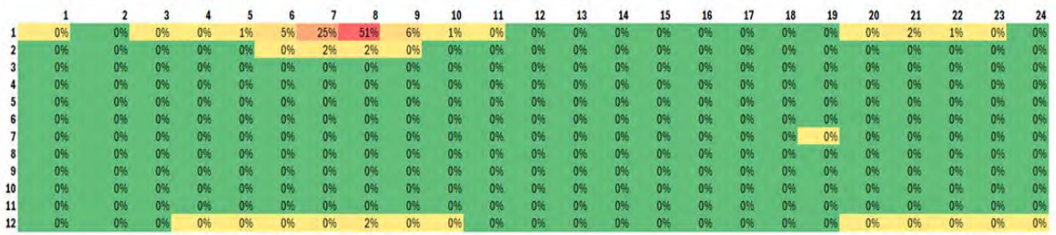
- LOLE Studies: These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also used in a reliability verification step within IRPs to ensure that proposed resource portfolios can meet reliability thresholds year-round, including accounting for net demand ramping and energy adequacy needs.
- ELCC Studies: These are a specific type of probabilistic assessment used to determine the capacity contributions of VERs such as solar, wind, and battery storage. Unlike non-variable resources like thermal units, which are typically counted at their nameplate capacity, VERs and energy storage undergo ELCC analyses to discount their nameplate capacity to firm, dependable capacity that effectively contributes to meeting LOLE reliability standards. ELCC studies account for factors such as the intermittent, diurnal nature of solar output, especially noting that solar output is minimal during typical winter peak loads (early morning and late evening).
- Statistical Modeling: Entities use detailed statistical modeling to establish separate summer and winter RMLs, considering factors like load forecast uncertainty, generator availability, and extreme weather impacts. While no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources.
- Stochastic Analysis in Load Forecasting: To account for the inherent uncertainties in demand, especially with the addition of large industrial customers like data centers, entities employ stochastic analyses. For instance, one entity uses a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects.
- Load Forecast Uncertainty (LFU) Scenarios: Planning processes integrate “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake. These scenarios directly drive planning reserve and resource-adequacy sensitivity cases, allowing planners to assess system resilience under different conditions.

Regarding non-peak hour risk and energy assessments, entities are in varied stages of implementing formal processes. While some currently lack established procedures, they acknowledge the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such assessments. As these formal energy risk assessments are initiated, future reports are expected to include risk quantification tied to specific drivers (e.g., fuel supply constraints, weather-driven demand volatility, system flexibility limitations) using probabilistic metrics across operational time frames, beyond just peak demand hours. These formal energy risk assessments, once fully implemented, are intended to be essential tools for informing strategic planning and operational decisions to ensure resource capacity is available across a broad range of conditions.

ProbA Results

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	143	231	538
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.16	0.33
*Provides the 2024 ProbA Results for Comparison			

The ProbA results for the year 2027 indicate some risk for SERC-East in the winter months of January and February. This is in line with the risk findings of previous ProbA studies. The annual EUE is 231.75 MWh but for a very short, expected duration of 0.15 hours. As shown in the 2027 EUE Heat Map below, the risk occurs during winter morning hours around 7:00-8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. The risk is seen mainly in January but on a smaller scale in the other winter months of February and December. The major contributing weather-years to the EUE in the model are 1982 and 1985, which experienced one of the worst winters throughout the SERC Region, limiting the amount of imports from neighboring subregions.



2027 EUE Heat Map

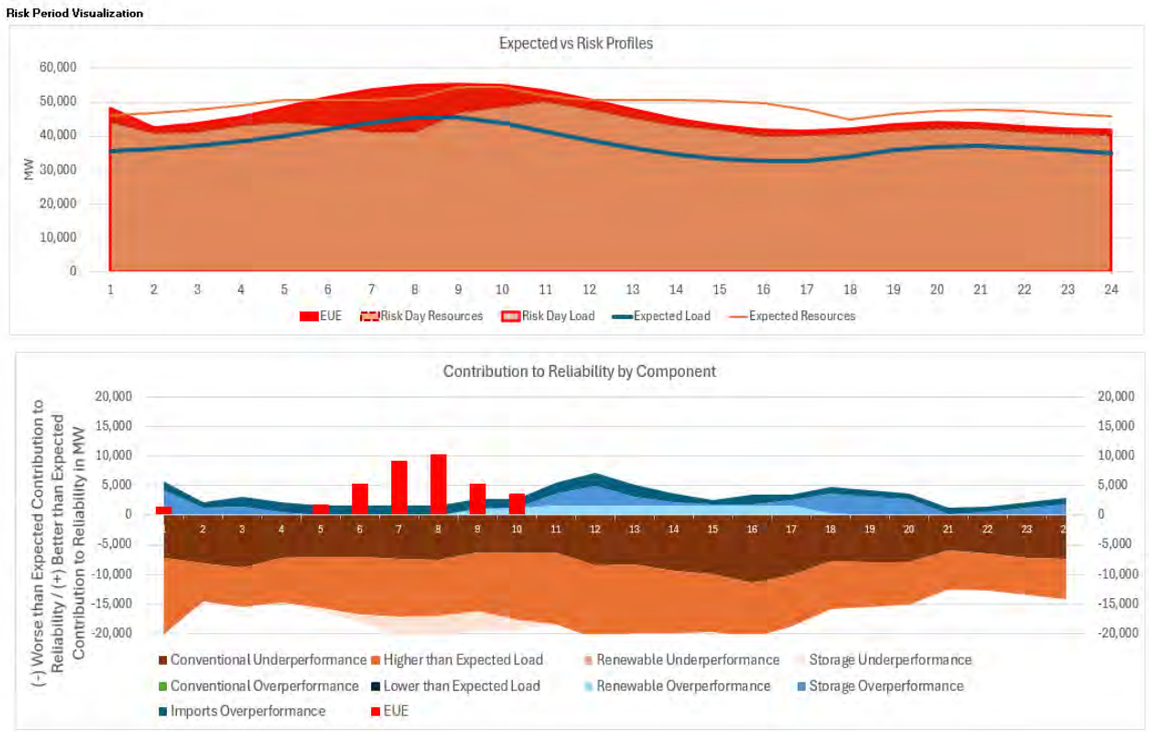
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	3%	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

For the year 2029, SERC-East risk continues to grow with 538.48 MWh of EUE and 0.33 hours of LOLH. As is shown in the 2029 EUE Heat Map above, the trends of risk are similar to the findings of 2027, with risk is expected to occur primarily in January, but other winter months of February and December as well. The expected duration of risk is still very short, occurs around 7:00-8:00 a.m. Load is expected to grow in SERC-East. In 2028, more than 1800 MW of coal is expected to retire. While there are some replacements with battery, solar generation, and DR, they are limited in the winter morning risk hours as seen in the study and contribute to the increase in EUE in 2029.

Between 2027 and 2029, the is an expected addition of 683 MW summer load and 985 MW winter load. In the last stages of the ProbA, SERC worked with its entities to identify an error in winter load forecast reporting. We are unable to rerun the model in time for the submission however, we are working with the entities to make the correction to the LTRA. For SERC-East, the overall 2029 winter load forecast should be 1932 MW than is currently reported. The expected risk would be higher along the same trends as is seen in the present study for the year 2029

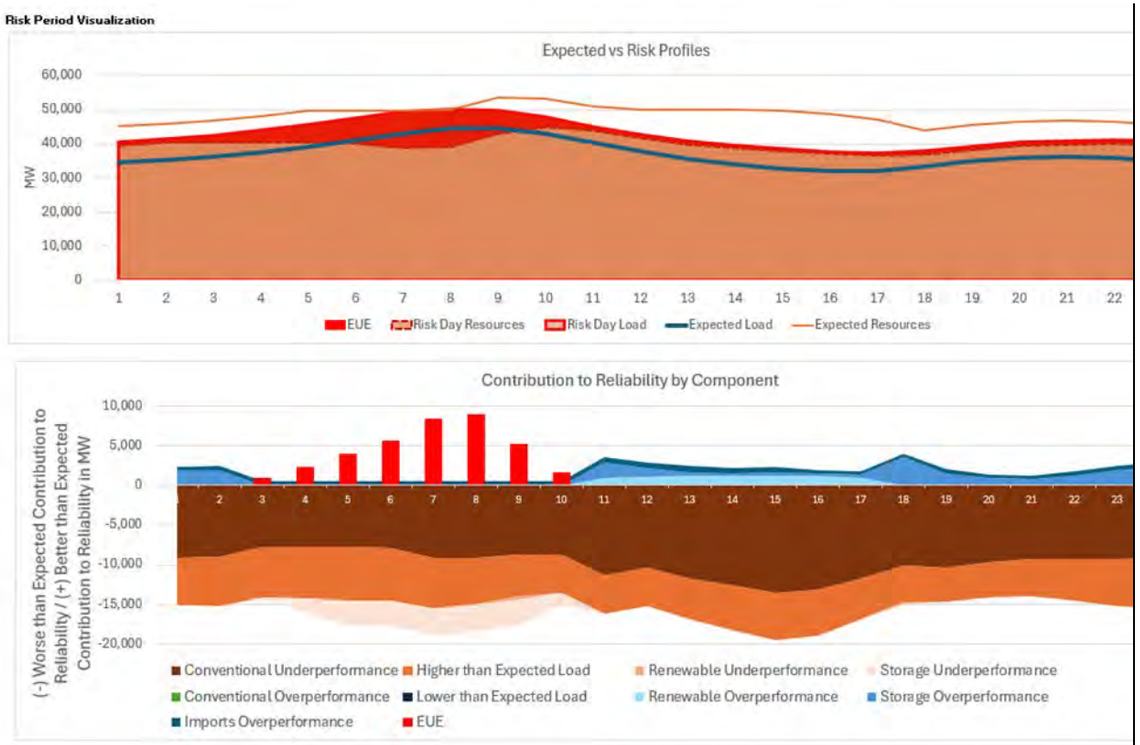
In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.



Expected vs. Risk Profiles and Contribution to Reliability by Component

The event day with the worst case EUE hour was chosen for reference (load forecast error +4%, weather year 1985, winter). The chart shows risk during winter morning hours from 4:00-10:00 a.m. and 12:00-1:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. Some imports from neighboring areas are available.

The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029. The event day with the worst case EUE hour was chosen for reference (load forecast error +2%, weather year 1985, winter).



Similar to the 2027 event, there is risk during winter morning hours from 3:00-11:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. While there are some imports from neighboring areas available, it is much lower in this event.

Demand growth and planned generator retirements contribute to growing energy risks. SERC and the SERC East entities will need to continue to monitor the resource adequacy studies.

Demand

The assessment area develops its load forecasts using a combination of short-run and long-run econometric techniques, which are then aggregated into a coincident system peak outlook. One entity uses statistically adjusted end-use (SAE) models for customer classes, supplemented by adjustments for energy-efficiency programs, rooftop solar, and EV forecasts from external consultants. Another entity applies SAE regression for residential and commercial classes, a consultation-based approach for large industrial customers, and a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects. Municipal and wholesale sub-area forecasts are integrated to form the coincident peak, with contracts having defined end dates removed to prevent overstatement of future demand. Load forecast uncertainty (LFU) is addressed through "High" and "Low" scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, driving planning reserve and resource-adequacy sensitivity cases. Since the 2024 LTRA, key refinements include the explicit addition of an EV demand component starting in 2025, more frequent updates for large industrial prospects, and expanded stochastic modeling to capture rising volatility from electrification and BTM generation.

Changes in the 10-year forecasted demand and energy growth rates since the *2024 LTRA* are primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These loads are accounted for via a post-modeling stochastic adjustment from active projects and are a significant driver, contributing approximately 1,100 MW by 2034. Electrification trends, particularly EV adoption, are also included, projected to increase residential and commercial summer peak demand by 33 MW and winter demand by 3 MW by 2034. Rooftop solar is forecast to offset summer demand by 3 MW, with no winter peak impact. Other potential drivers like geographic/demographic shifts, economic outlook, EE (beyond standard modeling), flexible loads, extreme weather, and climate change are currently not considered significant contributors to forecast changes. Beyond the 10-year window, electrification and industrial expansion are expected to continue influencing demand, though uncertainty increases.

Demand-Side Management

DR programs are actively monitored and managed through contractual agreements, control technologies, and performance metrics. DR capacity primarily supports the grid during peak periods, with one entity's capacity mainly from interruptible loads and customer standby generation based on contracted firm demand. Programs focus on winter peak capacity support with some summer use but do not currently address ancillary services. Recent initiatives include a residential DR program (smart thermostat rewards, peak time rebates, time-of-use education) and a residential DR program with load control switches on HVAC units and water heaters, contributing about 2.3 MW based on industry benchmarks. However, efforts to develop more precise baselines for measuring performance have yielded inconsistent results, especially in winter, leading to continued reliance on industry averages. Plans include piloting a "Bring Your Own Thermostat" initiative and transitioning to smart thermostat and other grid-edge technologies due to limitations of current switch-based programs.

Since the *2024 LTRA*, regulatory approvals have expanded incentives for most residential controllable programs (heat strip control, thermostats, water heaters, batteries, except the newer battery program) and increased program coverage. This includes a statewide water heater switch program

launching in 2025, adding November as a winter control month, and enabling year-round water heater control. Emerging technologies like EV batteries, smart panels, home automation, and smart inverters are being monitored for future inclusion. A multi-year initiative has been approved to quantify broader value streams from DR, potentially including energy, regulation, and ancillary services. For non-residential customers, a "Bring Your Own kW" winter load curtailment program is expanding, and two new 2025 programs offer an economic curtailment option and a shorter emergency curtailment program. A planned retirement of one large customer DR program aims to streamline offerings into a unified portfolio called PowerShare.

No major changes have been reported for EE and conservation since the *2024 LTRA*, but refinements are being considered. EE impacts are integrated into load forecast models as post-modeling adjustments, reflecting incremental improvements and new program designs. EE is embedded within customer class forecasts and refined through stakeholder input and ongoing evaluation. Looking ahead, increased focus is expected on load-modifying technologies, smart home integration, and more dynamic EE measurement approaches, potentially through real-time metering data or integration with distributed energy resource management systems (DERMS).

Distributed Energy Resources

DERs, particularly BTM solar PV, are anticipated to experience gradual growth within the assessment area over the next 5 and 10 years, although their current penetration levels remain low. Forecasts project residential solar installations to grow by approximately 8% in 2025, tapering slightly to 7% in 2026 and 2027, and then stabilizing around 6% annually thereafter. These projections are informed by local adoption trends, national market dynamics, and regression models that consider economic payback factors such as installation costs, incentives, and bill savings. Historical metering data also shows a recent decline in new BTM installations due to the expiration of DER incentive programs, which influences future projections.

In terms of integration into planning, BTM solar generation is primarily treated as a load modifier, effectively reducing net load through hourly profiles consistent with prior methodologies. Transmission planning similarly incorporates DER generation as a load reduction rather than a supply resource. For generation planning, the capacity value of solar is assessed through ELCC studies due to its intermittent and diurnal nature. Unlike fully dispatchable thermal resources, which are counted at their full nameplate capacity, solar output varies and typically yields minimal output during early morning and late evening winter peak loads. Summer peak loads align better with solar generation, but its capacity contribution still requires careful assessment through ELCC to discount nameplate capacity to firm, dependable capacity to meet LOLE reliability standards.

The system-level impact of current BTM solar on peak demand and load shapes has been minimal, with no significant operational issues identified from existing penetration levels. BTM solar output is projected to represent only 1% to 1.5% of system load over the planning horizons. While no DER-related reliability risks are anticipated for summer 2025, entities are monitoring for potential localized impacts on midday load in areas with higher solar density. Aside from solar PV, no other types of BTM DERs are currently known to materially affect demand-side profiles.

Regarding DER aggregators, there are currently no active or projected aggregators contributing to electricity demand management within the assessment area, and no such capacity is included in forecasts for the next 5 or 10 years. No formal programs are in place to involve DER aggregators in wholesale electricity markets or Integrated Resource Plans, and no virtual power plants operate within the system. While broader grid reliability studies, particularly concerning IBRs, have been conducted through collaborations like the Eastern Interconnection Planning Collaborative, these efforts have not yet extended to DER aggregation. However, if DER aggregator participation increases in the future, planning practices will be adjusted accordingly.

Since the *2024 LTRA*, there have been no major modifications to DER monitoring or modeling methods. However, future updates aim to distinguish between solar-only and solar-plus-storage DERs. Load forecast uncertainty (LFU) scenarios do account for rooftop solar penetration and BTM generation, reflecting the rising volatility introduced by electrification.

Generation

Generation planning and management within the assessment area involve a comprehensive set of studies and strategies to ensure reliability amidst an evolving resource mix and increasing load growth.

Overall Planning and Resource Mix Evolution

Entities in the assessment area conduct extensive reliability studies as part of their resource planning, including resource adequacy and LOLE studies, typically targeting a reliability standard of no more than 1 day in 10 years. These studies inform integrated resource planning (IRP) processes, which evaluate new generation scenarios and resource transitions.

The resource mix is undergoing significant changes, driven by the following:

- **Retirements:** Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are contingent on securing sufficient replacement capacity to maintain reliability and a target winter reserve margin. For instance, Roxboro units are expected to retire 1,156 MW by 2028 and 1,402 MW by 2033, and Mayo 763 MW by 2030, all dependent on replacement capacity being online. Planning entities proactively manage

these risks through transmission impact studies and will delay retirements if replacement resources are not operational.

- **New Additions:** To meet growing demand and replace retiring capacity, IRPs identify substantial new resources through 2035. These include thousands of megawatts of solar, battery storage, wind, combustion turbines (CT), combined cycle (CC) units, and small modular nuclear reactors (SMR). Some entities are also replacing coal-fired generation with natural gas combined-cycle (NGCC) units to introduce more flexible, dual-fuel generation that supports VER integration.
- **Load Growth:** Significant winter load growth of around 2% annually is projected between 2025/2026 and 2034/2035, increasing winter peak demand by approximately 6,500 MW. This growth is primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These high-load, high-duty-factor customers require resource portfolios capable of sustaining elevated energy demand beyond typical seasonal peaks.

Capacity Valuation and Reliability
For resource adequacy, entities determine PRMs to meet reliability standards.

Capacity Contribution Values: Capacity contributions for different generation types are assigned using a mix of historical performance data and model-based simulations:

- **Variable Energy Resources (VER):** For intermittent resources like solar, onshore wind, offshore wind, and storage, ELCC studies are essential. ELCC studies discount the nameplate capacity of VERs to determine their firm, dependable capacity to meet LOLE reliability standards. Solar output varies and often yields minimal output during early morning and late evening winter peak loads, though summer peak loads align better with solar generation. ELCC values for solar and battery storage are typically updated every three years.
- **Thermal Resources:** Non-solar, wind, and storage resources, such as thermal units, are generally counted at their full nameplate capacity.
- **Hydro Resources:** For hydro-only entities, capacity contributions are based on hydro capacity and remain stable.

Reserve Margins: Reserve margins are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. One entity, however, anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and has increased its winter reference PRM from 12% to 18%. Another entity plans to adopt a 22% winter reserve margin by 2031.

Operational Considerations
Planning activities are actively underway to address potential operational issues from the evolving resource mix:

- **Ramping Needs:** Planning entities estimate ancillary service needs, such as regulation, balancing, and contingency reserves, to ensure operational reliability amid high penetrations of VERs. While some entities with hydro-based or dispatchable, fast-ramping units have no immediate ramping concerns, and others conduct triennial integration studies aligned with their IRPs to assess the system's ability to integrate intermittent generation.
- **Inertia and Stability:** Stability assessments are conducted as part of TPL-001 compliance and interconnection cluster studies. These studies account for new generators and evaluate the growing share of VERs. Results thus far have not revealed significant stability concerns. If a weaker area with lower inertia is identified, further analysis like EMT modeling may be conducted, and adjustments to IBR performance settings or transmission system upgrades are considered.
- **IBRs:** As solar PV integration grows, interconnection studies now mandate the use of EMT models to evaluate IBR performance during disturbances, addressing issues like momentary cessation and fault ride-through. These studies ensure inverter settings comply with NERC standards (e.g., PRC-024) and FERC Order 827. Efforts focus on maintaining network reliability and system stability. While no new ancillary service needs have emerged in the near five-year horizon, entities are considering adopting IEEE 2800 standards.
- **Natural Gas Fuel Supply Risk:** Planning entities have implemented measures to mitigate risks from natural gas fuel supply disruptions, especially during extreme weather. All natural-gas-fired combined cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Future resource planning assumes on-site backup fuel or dual-fuel capability. Long-term studies factor in fuel supply constraints and infrastructure bottlenecks.

Energy Storage
Energy storage (ES) systems, particularly BESS, are anticipated to see significant capacity installations over the coming decade.

Purpose: Much of the planned BESS will be paired with solar facilities to store excess solar generation and enhance system flexibility. The region also operates substantial pumped hydro storage, used to meet load economically and manage generation ramping requirements.

Integration: Energy storage projects are evaluated through generator interconnection studies, modeling both charging and discharging behaviors. Both standalone and hybrid (paired with renewable generation) storage systems are planned for deployment.

Modeling: BESS are modeled assuming a four-hour discharge duration, with capacity contributions varying based on system conditions and resource mix. Hybrid and standalone battery systems are evaluated using ELCC to capture their effective capacity contribution during peak demand periods.

Capacity Transfers

Energy transfer needs and capabilities are undergoing changes, primarily driven by anticipated load growth and the potential retirement of generation resources.

While one generation-only BA does not foresee any changes to its transfer capabilities, other entities acknowledge that the potential retirement of coal plants could constrain transfer capability. To address these potential constraints, new transmission projects are being evaluated and planned. In response to increasing load demands, particularly within specific BAs, multiple active transmission projects are underway to enhance near-term transfer capabilities. Firm transmission service contracts have been secured to support future transfer needs tied to generator retirements, indicating a reliance on these transfers to maintain reliability. Long-term transmission and resource adequacy planning efforts, including IRPs and coordination with neighboring utilities, are ongoing to ensure the region maintains sufficient capacity and transfer reliability. Planning entities model projected resource additions and retirements and incorporate these into transmission models to identify and address any negative impacts through reliability assessments. Long-term firm imports have been requested from neighboring regions to assess whether external capacity transfers might be more cost-effective than developing new local resources, highlighting a consideration for reliance on external capacity for reliability and economic reasons. Potential organizational changes, such as merging BAs, are also being modeled and assessed to ensure system reliability is maintained.

Transmission

Major transmission projects are identified through annual planning assessments to support and maintain system reliability. These projects include new transmission lines (including HVdc), reconductor projects, and power electronic devices like static var compensators (SVC). For instance, a new 230 kV line and synchronous condensers are planned to improve reliability and reduce congestion in coastal areas, and an additional circuit in South Carolina will address low-country congestion. Transmission limitations and constrained areas are identified through annual assessments, but no widespread transmission-constrained areas have been identified in recent planning studies. However, an operating guide exists to manage potential overloads on a specific transmission line. Interconnection study processes are crucial for detecting and resolving potential constraints before new generation is brought online, which helps prevent congestion during real-time operations. Since the *2024 LTRA*, there have not been major changes to transmission planning processes, but entities are actively responding to evolving regulatory requirements, such as FERC Order No. 2023. This includes developing new processes for interconnection heat maps, implementing updated interconnection and affected system processes (including cluster studies), and evaluating grid-enhancing technologies (GET). A business practice is being developed to formalize how GETs will be assessed in both transmission planning and interconnection analyses.

In summary, capacity transfers are important for reliability in this assessment area. System adequacy is maintained through proactive planning for new transmission projects, securing firm transfer contracts, evaluating external imports, and continually refining planning processes to accommodate evolving load and resource dynamics.

Reliability Issues

Entities in East have identified several key reliability issues primarily stemming from projected load growth, an evolving resource mix, and critical infrastructure interdependencies. These challenges necessitate proactive planning and operational adjustments to maintain BPS reliability.

Firstly, large, new load additions, particularly data centers and other industrial facilities, are the primary drivers of significant changes in the 10-year forecasted demand and energy growth rates. These high-load, high-duty-factor customers could strain both generation and transmission resources if not adequately planned for. One entity anticipates potential reserve margin challenges starting in Winter 2027 due to these significant new load additions and is proactively issuing requests for proposals for new capacity resources. All substantial new loads are subjected to interconnection studies to assess their reliability impacts and determine necessary transmission upgrades.

Secondly, the management of generator retirements and the assurance of sufficient replacement capacity pose a significant reliability concern. Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are strictly contingent on securing firm replacement capacity to maintain reliability and meet a target winter reserve margin (e.g., 22%). If firm replacement resources are not in place, coal retirements would be deferred to preserve system reliability. Planning entities actively manage these risks by conducting thorough transmission impact studies to evaluate the effects of retirements on system reliability and to determine required transmission upgrades and replacement generation before allowing retirements to proceed.

Thirdly, the evolving interdependencies with other critical infrastructure sectors, especially natural gas fuel supply, are a major reliability issue, particularly during extreme weather conditions. The risk to BPS reliability from natural gas generator fuel supply issues, such as production or transportation

curtailments, is a recognized concern. Mitigation measures include ensuring that natural-gas-fired combined-cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Coordination protocols exist between electric and natural gas operators for both routine operations and emergency response, including maintaining electric service to critical gas infrastructure like compressor stations. Long-term studies also factor in fuel supply constraints and infrastructure bottlenecks, drawing insights from past events.

Fourthly, the operational impacts of the changing resource mix, particularly the increasing penetration of VERs and IBRs, are actively being addressed. Stability assessments are routinely conducted as part of TPL-001 compliance and interconnection cluster studies to evaluate inertia and transmission stability. While results so far have not revealed significant stability concerns, further analysis, such as EMT modeling, may be conducted in identified weaker areas with lower inertia. Interconnection studies for IBRs now mandate the use of EMT models to evaluate their performance during disturbances (e.g., momentary cessation, fault ride-through) and ensure compliance with NERC standards and FERC Order 827. Additionally, ensuring sufficient flexible resources are available to meet expected system ramping needs is a key planning consideration, with triennial integration studies assessing the system's ability to integrate intermittent generation.

Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages with neighboring utilities and prioritizes reliance on internal generation rather than market purchases during these vulnerable periods. For extreme cold weather, a specific temperature threshold triggers the inclusion of additional operational reserves in its planning process, supported by enhanced forecasting tools. While no widespread transmission-constrained areas have been identified in recent planning studies, new transmission projects are being evaluated and planned to enhance transfer capabilities in response to increasing load demands and potential coal plant retirements, indicating ongoing efforts to prevent future transmission-related reliability issues.

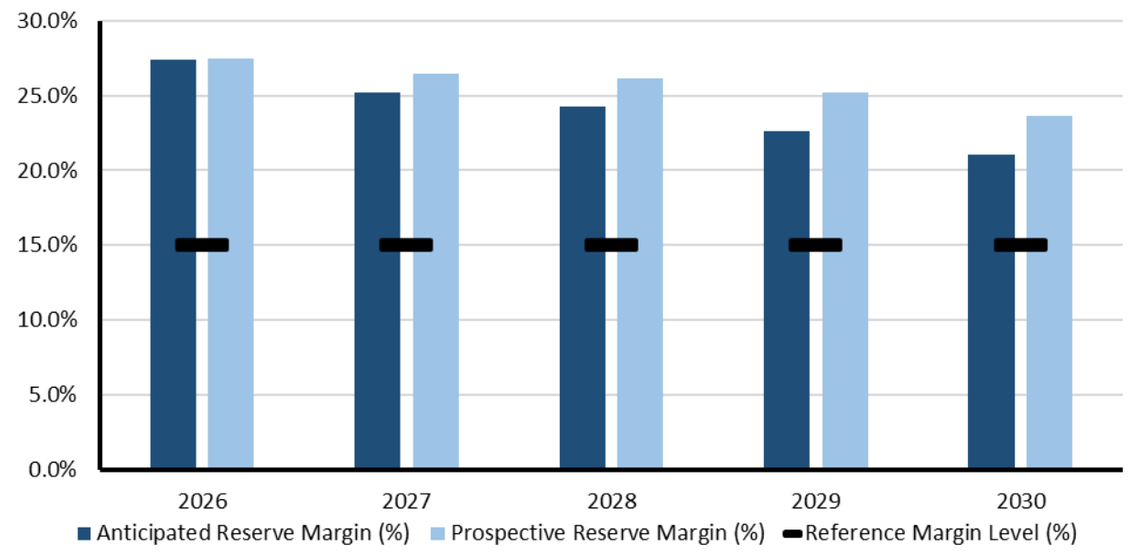


SERC-Florida Peninsula

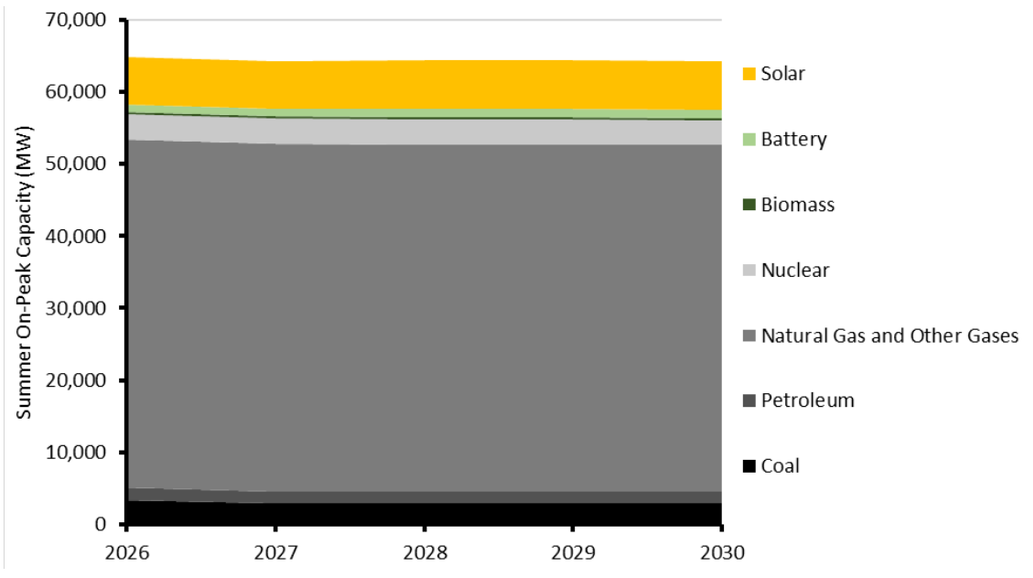
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across 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 Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	54,477	54,933	55,377	56,099	56,666	57,414	58,267	58,972	59,724	60,415
Demand Response	3,345	3,345	3,357	3,360	3,368	3,379	3,388	3,400	3,412	3,418
Net Internal Demand	51,132	51,588	52,020	52,739	53,298	54,035	54,879	55,572	56,312	56,997
Additions: Tier 1	754	800	997	1,000	1,001	1,801	1,801	1,802	1,803	1,803
Additions: Tier 2	32	620	962	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	293	293	200	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	64,393	63,795	63,659	63,659	63,525	63,001	62,966	62,966	62,966	62,966
Anticipated Reserve Margin (%)	27.4%	25.2%	24.3%	22.6%	21.1%	19.9%	18.0%	16.5%	15.0%	13.6%
Prospective Reserve Margin (%)	27.5%	26.4%	26.2%	25.2%	23.7%	22.5%	20.5%	19.0%	17.5%	16.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Highlights

- SERC-Florida Peninsula's ARM falls below the RML during the 2035 time frame.
- SERC-Florida Peninsula's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	3,361	2,902	2,902	2,902	2,902
Coal*	3,346	2,418	2,418	2,418	2,418
Petroleum	1,795	1,667	1,667	1,667	1,667
Petroleum*	1,768	1,459	1,459	1,459	1,459
Natural Gas	48,214	48,202	48,159	48,159	48,025
Biomass	310	310	310	310	310
Solar	6,666	6,712	6,814	6,817	6,818
Nuclear	3,502	3,502	3,502	3,502	3,502
Battery	1,000	1,000	1,095	1,095	1,095
Total MW	64,849	64,297	64,450	64,453	64,321
Total MW*	**64,806**	**63,604**	**63,757**	**63,760**	**63,628**
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The Florida Peninsula subregion annually assesses its PRMs to ensure the regional total reserve margin (TRM) requirement is met over a 10-year projected period, considering summer and winter peak loads, generating resources, and firm DSM resources. The State of Florida's Public Service Commission (FPSC) reliability criterion of a 15% reserve margin serves as the general TRM for entities in the subregion. Notably, investor-owned utilities (IOU) in the subregion voluntarily maintain a higher 20% reserve margin, which also functions as their RML based on firm load. These subregional TRM calculations incorporate merchant plant capacity that is under firm contract to load-serving entities.

Currently, the ARM for the Florida Peninsula subregion is projected to remain above the RML throughout the entire assessment period, indicating no present concerns regarding resource adequacy due to reserve margin deficiencies. Specifically, the projected Regional TRM is above the NERC RML of 15%, and Florida Peninsula subregion reserve margins are anticipated to stay at or above 20% for all summer and winter seasons during the assessment period. This healthy reserve level, coupled with excess import capability, means that the subregion does not foresee changes to its energy transfer needs or capabilities.

Probabilistic analyses confirm that the Florida Peninsula subregion continues to operate below this 0.1 loss of load probability (LOLP) standard. The methods used to calculate the Florida Peninsula RML have remained consistent since the prior LTRA. While individual planners account for uncertainty and variability before submitting their data, which is then aggregated, energy adequacy concerns are not directly addressed within the immediate calculation of ARM/RML. Instead, energy adequacy is reviewed through a biennial Loss of Load Probability Study, which assesses all hours of the year, as well as through transmission and fuel reliability study work. Although no formal changes have been made to existing resource adequacy planning or procurement processes since the *2024 LTRA*, the Florida Reliability Coordinating Council (FRCC) and individual entities are actively considering enhancements, particularly focusing on the increasing penetration of IBRs to ensure sufficient dispatchable generation for potential energy assurance concerns. The FRCC is also continuing to develop its analysis of the 24-hour load and resource outlook around peak days to better understand the impact of increased solar penetration and energy storage charging/discharging on ARM/RML.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The Florida Peninsula Subregion undertakes energy risk assessments to understand its ability to meet uncertain forecasted system demand, particularly as traditional resource adequacy approaches face shortcomings with increasing variability. These assessments are primarily conducted through biennial loss-of-load probabilistic (LOLP) assessments, which are distinct from NERC's ProbA and are designed to assess energy adequacy across every hour of a five-year study period, rather than solely focusing on seasonal peaks. Inputs for these studies include projected generating unit information (current and future capacity), seasonal demand values, projected DR availability, generation maintenance schedules, and Forced Outage Rates (FOR). The FRCC utilizes Astrapé's SERVM Software for multiple base case and sensitivity LOLP studies, with scenarios often examining conditions like no firm import availability, no DR availability, or a 90/10 load case.

These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. The analysis has indicated no expected hours of shortfall in adequacy through 2034, though it has observed that increasing solar levels tend to shift the hours of thinnest reserve margins in the summer to later in the day (specifically, HE 18–19).

The FL-Peninsula subregion assesses system adequacy against the industry standard metric of 0.1 LOLP, which equates to approximately one event every 10 years, and currently remains under this standard. Although no significant adequacy impacts have been identified for off-peak hours and shoulder periods, the subregion entities are continuously working to improve their probabilistic analysis methodologies and enhance the robustness of their assessments for these periods. The results of these energy risk assessments are foundational for proactive planning, risk mitigation, and regulatory compliance, guiding long-term strategic decisions like infrastructure development and resource procurement, as well as short-term operational preparedness. The FRCC and its members are also actively considering enhancements to these processes, particularly focusing on the increasing penetration of inverter-based resources (IBR) to ensure sufficient dispatchable generation for potential energy assurance concerns.

ProbA Results

Based on the data and assumptions of SERC's ProbA model, SERC-Florida Peninsula does not show any loss of load in 2027. For 2029, the annual, probability weighted risk is 0.094 MWh and the LOLH is 0.0001 hours. This is summarized in the table below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	0	0.094
NEUE (ppm)	0.01	0.00	0.00
LOLH (hours per Year)	0.01	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

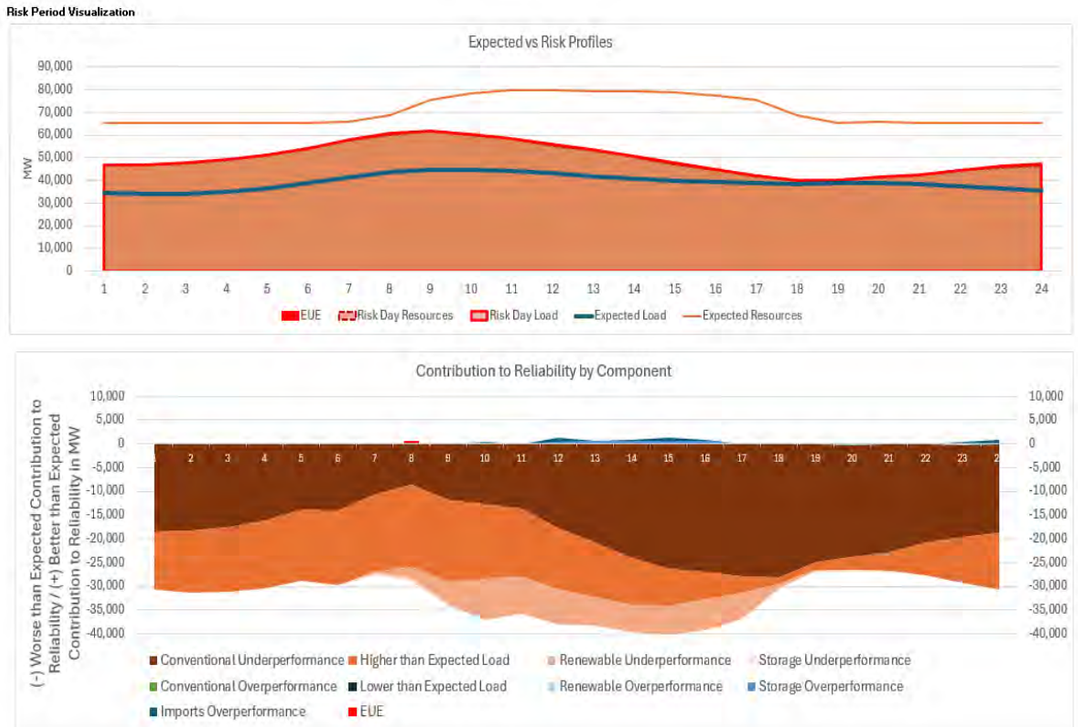
2027 EUE Heat Map

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

As seen above, the 2027 EUE heat map does not show any risk hours. For study year 2029, there is only one out of 5,375 cases that show risk, which is for a load forecast error of +4%, and weather years 1985 which was an extreme winter year. For that one case, SERC-Florida Peninsula shows an EUE of 720 MWh, with all the risk in December at 7:00-8:00 a.m.

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029 show event details for one risk event for 2029.



Expected vs. Risk Profiles and Contribution to Reliability by Component

Above, the event day as higher than expected load (extreme winter 1985, 4% load forecast error) and resources available are less than expected. The above shows the risk hour to be between 7:00-8:00 a.m. when solar generation is limited, storage and imports are limited. There is some conventional generation on outage.

SERC-Florida Peninsula is also seeing load growth, with an addition of 1,551 MW winter load and 1,146 MW summer load between 2027 and 2029. While the subregion continues to add solar generation, this study indicates that it would not help alleviate risk in cases of extreme winter mornings when solar generation would be very limited.

With the heavy dependence on natural gas in the SERC-Florida Peninsula subregion, fuel diversity could become an area of future concern. Entities in FL-Peninsula have reported a high number of dual-fuel units to mitigate potential disruptions in the natural gas pipelines. Additionally, a new gas pipeline and connection hubs were constructed in the past few years to provide additional gas to the SERC-Florida Peninsula units. The growing penetration of renewable energy means that SERC and the SERC-Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.

Demand

The Florida Peninsula subregion's approach to demand forecasting involves individual entities developing their own load forecasts, which are then aggregated by the FRCC to calculate a non-coincident seasonal peak for the subregion. These individual entities annually adjust their forecasts to account for factors such as actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and EE efforts, and electric appliance usage patterns.

The net energy for load (NEL) as well as summer and winter peak demands are forecasted to grow, with the current average annual growth rate for NEL at 1.1% per year, and firm summer and winter peak demand growth expected to increase to 1.34% and 1.45%, respectively, implying a declining trend for the regional load factor. While some larger utilities account for load profile modifiers like DERs and EVs, smaller utilities either lack sufficient data or deem their current impacts as minimal. The penetration of dependable ac solar capacity and EVs is currently low but expected to grow steadily. LFU is assessed at the individual entity level but is incorporated in FRCC and SERC probabilistic analyses for determining potential Loss-of-Load metrics, though not at the subregional level for Total Demand calculation.

Overall, demand and energy growth rates are projected to increase slightly (between 0.15% and 0.3%) compared to the previous LTRA, driven by population growth, economic performance, electricity prices, changing technology and consumption patterns, and more-efficient building codes. Higher-than-normal temperatures have played a noticeable role in higher average consumption per customer. The impact of data centers or similar large loads is currently minimal and not anticipated to create reliability concerns within the planning horizon, and insights beyond the 10-year forecast are not provided.

Demand-Side Management

DSM programs, controllable and dispatchable DR programs within the Florida Peninsula subregion are treated as a load modifier, projected to remain constant at approximately 6% of the summer and winter total peak demands throughout the assessment period. Each reporting entity independently develops its forecast of firm controllable and dispatchable DR values based on their specific methodologies and program policies, with the FRCC aggregating these impacts for regional analytical purposes. In addition to utility-sponsored EE programs, many utilities also include forecasts of EE associated with the impact from governmental codes and standards. Trends in both utility-sponsored EE and EE from governmental codes and standards remain consistent with prior years, and no modifications have been made to these methods or assumptions since the previous LTRA. Looking forward over the next 10 years, while no changes to how EE and conservation are measured or accounted for have been implemented since the 2024 LTRA, enhancements are actively being considered. These considerations include improved hourly granularity, standardized methodologies, advanced measurement and verification techniques, and better integration of EE into long-term resource planning to support system reliability amidst growing energy demands and increasing renewable integration.

Distributed Energy Resources

The Florida Peninsula subregion systematically monitors and integrates DERs into its planning processes, primarily focusing on BTM solar PV as the most significant type of DER currently identified.

Penetration and Trends: The FRCC conducts an annual collection of DER data across its membership, as reflected in the Load and Resource Plan. While DER penetration levels, particularly for private dependable ac solar capacity and EVs, are currently relatively low, they are forecast to increase steadily over the planning horizon. This includes observed and anticipated year-over-year increases in BTM PV penetration, though these levels remain low compared to the total demand of the Florida Peninsula subregion.

Accounting and Integration in Planning: Entities within the subregion utilize NERC-published definitions for DERs. In general, DERs are modeled as being netted out with the actual customer demand, as their impacts are implicitly accounted for within the load forecasts developed by individual entities. Some larger utilities specifically account for DERs and EVs as load profile modifiers in their forecasts.

Monitoring and Studies: The FRCC's Load Forecast Working Group (LFWG) meets annually to monitor trends in demand sensitivities related to DERs and coordinates on best practices. Additionally, resource planning, transmission planning, and stability analysis subcommittees annually review DER penetration levels to assess whether further study work or sensitivities are required.

Challenges and Reliability Impacts: No additional challenges or significant operational issues have been identified by PCs and Transmission Planners in the assessment area stemming from increased

DER penetration levels at this time. The subregion has not identified any significant BTM resources other than solar PV.

DER Aggregators: Currently, the FRCC and its members do not collect additional data from third-party DER aggregators beyond what is already included in the members' integrated resource plans via their annual data collection process.

Generation

The Florida Peninsula subregion is actively managing its generation fleet to maintain reliability amidst an evolving resource mix, with a particular focus on the increasing integration of IBRs like solar and battery installations, and its continued reliance on natural gas.

Here are the key details regarding generation in the subregion:

- Changing Resource Mix and Operational Considerations:
  - While no significant operational issues have been identified at this time due to the changing resource mix, FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels (solar and battery installations).
  - The FRCC Operating Committee (OC) monitors actual output of solar units and tracks how much additional solar capacity will be online within the next 18 months, discussing any operational issues at monthly meetings.
  - Transmission planning studies, including short-circuit ratios and transient stability analyses, have been conducted to assess the performance of existing and planned IBR installations. These studies indicate that the FRCC system is anticipated to maintain reliable stability performance under expected IBR penetration levels in the five-year planning horizon, with no TPL performance issues identified.
  - Additional study sensitivities include light load conditions with solar modeled at projected output and system strength evaluations.
  - IBR performance issue risks are not considered significant in the near term for the assessment area relative to synchronous capacity.
  - The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.
- Natural Gas Reliance and Fuel Supply Risk
  - The Florida Peninsula subregion is not expecting any long-term reliability impacts resulting from an increased reliance on natural gas-fired generation.
  - The Fuel Reliability Working Group (FRWG) and Resource Subcommittee (RS) periodically study current and projected natural-gas-fired generation levels, including analyses of long-term infrastructure requirements, potential loss of compressor stations, availability of alternate fuel, and extreme weather analyses.
  - Entities in the subregion do not anticipate natural gas supply issues to create reliability risk.
  - Members are projected to hold the vast majority (approximately 90%) of firm pipeline capacity delivering into Florida, supporting increasing gas generation requirements.
  - In the event of a short-term failure of gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand. Approximately 55–57% of natural gas generation has alternate fuel capability.
  - Communication protocols include fuel data status reporting by Operating Entities (OE) to the FRCC State Capacity Emergency Coordinator (SCEC) and FRCC RC during threats to fuel availability, integrating this data into enhanced daily capacity assessments.

Net Demand Ramping

No entity has identified any potential issues with net demand ramping within the 10-year planning horizon, as sufficient flexible resources are available. Potential ramping changes are not seen as emerging given current IBR penetration levels and the availability of dispatchable resources. FRCC planning and operating subcommittees plan to further evaluate aggregate system ramping needs over the next few years.

Capacity Contribution Values

Estimates for VERs, including wind, solar, and hydro, and energy storage, are determined by individual members based on actual performance of existing resources and projected performance using industry standard modeling tools (e.g., PVsyst).

Generator Retirements

Confirmed retirements are incorporated into the *Load and Resource Reliability Assessment Report*, while unconfirmed retirements are not tracked. Retirement decisions are made by each entity based on factors such as unit end of lifespan, operating costs vs. new alternatives, environmental regulations, and local sustainability targets. The subregion is not anticipating any negative impacts on reliability from retirements. Confirmed retirements projected have decreased from approximately 3,400 MW in the prior LTRA to 2,150 MW in the current analysis. Entities analyze projected resource

needs in their annual 10-year site plans (TYSP), which include planned retirements and new generation facilities.

Energy Storage

ES is increasingly being integrated into the planning processes within the Florida Peninsula subregion, with methodologies continuously evolving as entities gain more experience in their planning and operation. While entities are modifying their planning processes based on this accumulating experience, no significant modifications have been made to the core VER methods or assumptions, which include ES, since the previous LTRA.

For deterministic analyses, energy storage units are anticipated to be available to provide energy at the time of peak at their full capacity, effectively contributing to peak capacity. However, for probabilistic analyses and energy adequacy assessments, entities are continuing to discuss methodologies to incorporate supply duration and charging time to better reflect the resource's characteristics over time. The FRCC's biennial loss-of-load probabilistic assessments, which review every hour of a five-year study period, help assess energy adequacy and can include considerations for ES.

The impact of energy storage on system adequacy is also evaluated through the FRCC's "2x24 Hour Analysis." This analysis reviews the 24-hour load and resource outlook, helping entities understand more completely the impact of increased solar penetration levels and energy storage charging and discharging across all hours of the peak days on the ARM and RML. This detailed hourly assessment helps observe how ES operations influence system adequacy throughout the day and has indicated no expected hours of shortfall through 2034.

The capacity contribution values for energy storage are determined by individual members, generally based on a combination of actual performance of existing resources and projected performance using industry standard modeling tools. The basis for the percentage capacity contribution considers the nameplate rating of each facility.

Energy storage installations, particularly battery installations, are considered alongside other IBRs. FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels, including these battery installations. The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.

Currently, PCs and Transmission Planners in the assessment area have not identified any additional challenges or significant operational issues specifically stemming from increased DER penetration levels, including ES.

Capacity Transfers

In the Florida Peninsula subregion, capacity transfers primarily refer to anticipated firm import and export values with neighboring assessment areas, particularly the Southern Balancing Authority. While these transfers are an integral part of regional planning, Florida is generally not reliant on external capacity transfers for its core reliability, due to its robust internal generation and healthy reserve margins.

The FRCC Load and Resource Plan (LRP) annually incorporates anticipated firm import and export values reported by member utilities. Recent projections indicate a decline in firm imports for the region over the past few years.

To ensure effective capacity transfers and assess their sufficiency, the Florida–Southern Interface owners conduct an annual transfer capability assessment. This assessment determines the available transfer capability between Peninsular Florida and the Southern Balancing Authority and between the Southern Balancing Authority and FPL Northwest. The results of the most recent analysis project that the interface capability is sufficient to meet anticipated firm import needs.

Transmission

The Florida Peninsula subregion has not identified any specific major transmission projects that impact or are needed to maintain reliability during the planning horizon that are not already identified in the Annual Regional Plan. The individual entities have planned projects that are primarily related to system expansion in order to serve their forecasted growing demand and resource integration and to ensure long-term reliability (beyond the planning horizon). At this time, there have been no changes made to the transmission planning process since last year's reporting.

Reliability Issues

The Florida Peninsula subregion generally maintains a strong reliability outlook, with no other significant emerging reliability issues identified at this time. The ARM is expected to remain above the RML throughout the entire assessment period, meaning there are no current concerns regarding resource adequacy related to reserve margin deficiencies and thus no reliance on Tier 2 resources or supplemental options. Similarly, no potential issues with net demand ramping have been identified within the 10-year planning horizon, and no additional challenges from increased penetration levels of DERs have been identified by PCs and Transmission Planners. Large industrial or commercial load additions, such as data centers, are not anticipated to create reliability risk in the subregion, nor have

any transmission-constrained areas been identified in planning studies. The subregion is also not reliant on external capacity transfers for its core reliability due to robust internal generation and healthy reserve margins.

Even though the Florida Peninsula subregion is not projecting any significant emerging reliability issues, there are areas that the assessment area continues to monitor closely and actively consider for future enhancements or reassessments, indicating underlying risks or concerns that could impact long-term reliability:

- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are "not considered significant in the near-term" for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and battery installations) is a "key area of focus."
- **Risks of Extreme Weather:** While the Florida-specific energy risk assessments note "no expected hours of shortfall," scenario cases are run that include altered projected load to reflect extreme conditions (e.g., a 90/10 case), demonstrating an awareness of these potential risks.
- **Dependency on Natural Gas as a Fuel Resource:** Despite that Florida does not anticipate any natural gas supply issues that may create risk to reliability and has developed robust mitigation strategies (such as holding approximately 90% of firm pipeline capacity and having 55%–57% of natural gas generation with alternate fuel capability), the area's "dependency on natural gas as a fuel resource" is still factor where possible impacts on the long-term reliability of the BES are continuously monitored.

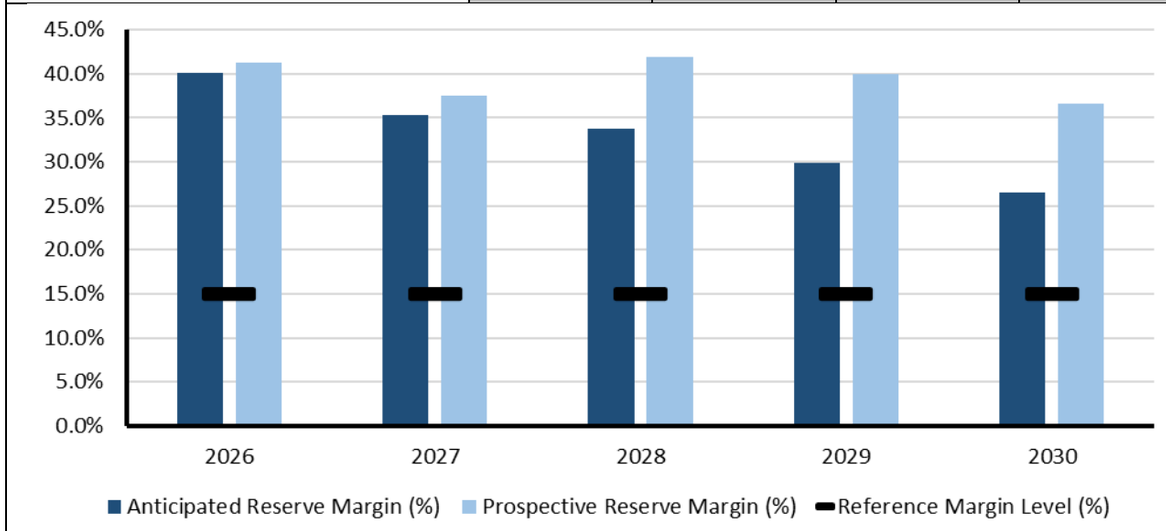


SERC-Southeast

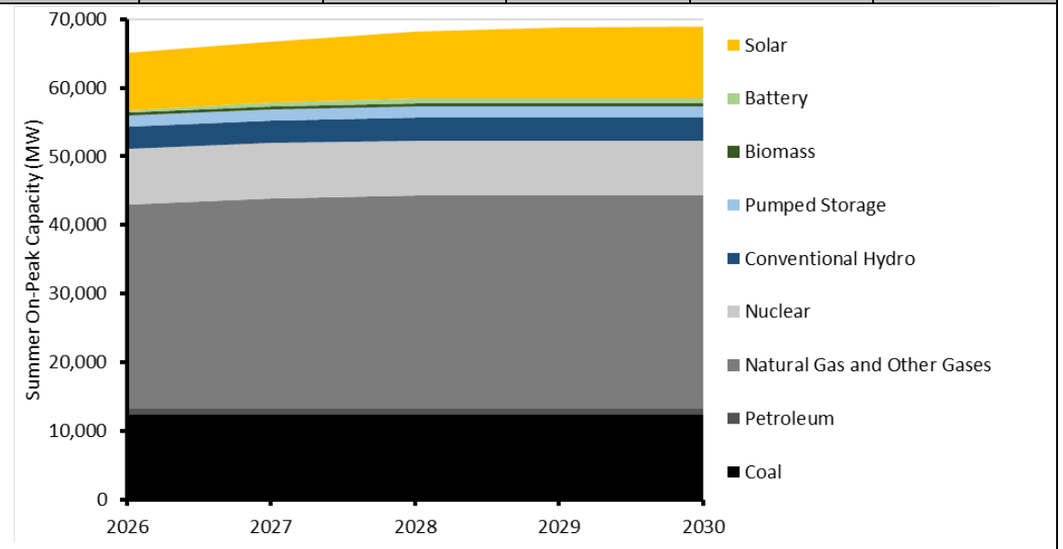
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. 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 Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	48,386	50,648	52,900	55,127	56,624	57,544	57,978	58,552	59,004	59,166
Demand Response	1,358	1,391	1,623	1,634	1,640	1,650	1,656	1,664	1,671	1,677
Net Internal Demand	47,028	49,257	51,277	53,493	54,984	55,894	56,322	56,888	57,333	57,489
Additions: Tier 1	684	2,262	3,704	4,395	4,474	4,474	4,474	4,474	4,474	4,474
Additions: Tier 2	0	516	3,687	4,889	4,989	4,989	4,989	4,989	4,989	4,989
Additions: Tier 3	0	150	250	500	500	500	500	500	500	500
Net Firm Capacity Transfers	814	-53	414	619	619	619	619	619	619	619
Existing-Certain and Net Firm Transfers	65,201	64,393	64,860	65,065	65,065	65,065	65,065	65,065	65,065	65,065
Anticipated Reserve Margin (%)	40.1%	35.3%	33.7%	29.8%	26.5%	24.4%	23.5%	22.2%	21.3%	21.0%
Prospective Reserve Margin (%)	41.3%	37.5%	42.0%	40.0%	36.5%	34.3%	33.3%	32.0%	30.9%	30.6%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Southeast Highlights

- SERC-Southeast's ARM does not fall below the RML during the 2025–2035 time frame.
- SERC-Southeast's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	12,403	12,403	12,403	12,403	12,403
Coal*	12,403	12,403	11,145	11,145	11,145
Petroleum	866	866	866	866	866
Natural Gas	29,765	30,646	31,057	31,057	31,057
Natural Gas*	29,751	30,632	31,043	31,043	31,043
Biomass	428	428	428	428	428
Solar	8,358	8,836	9,667	10,358	10,358
Conventional Hydro	3,292	3,292	3,292	3,292	3,292
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	279	557	757	757	836
Total MW	65,042	66,678	68,120	68,811	68,890
Total MW*	65,042	66,678	66,862	67,553	67,632
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

PRMs in the Southeast assessment area highlight a proactive and stable approach to ensuring grid reliability, with ARMs projected to remain above reference or target levels throughout the long-term assessment period. Utilities in the region typically plan for a 15% reserve margin, a target that has remained unchanged from prior years. Capacity plans are specifically designed to maintain 15% reserve margins in summer and 25% in winter, consistent with previous long-term assessments. The annual IRP process is crucial, as it addresses resource adequacy well in advance, ensuring that reserve margins consistently stay above these required levels, considering both primary and secondary generation resources.

The methodologies for determining these RMLs are robust and comprehensive. A LOLP analysis is conducted to ascertain if adjustments are necessary to maintain a 1-in-10-year LOLE. This analysis relies on assumptions concerning system loads, potential outages, transfer capabilities, and resource plans, drawing from historical and forecasted data. To account for uncertainties, these assumptions are stress-tested through Monte Carlo simulations across a range of best- and worst-case scenarios, calculating EUE at current RMLs. One utility, which operates independently of state regulatory oversight, conducts its own triennial reserve margin study (RMS) to pinpoint an economically optimal reserve level. This RMS balances capacity costs, production costs, and the costs associated with unserved energy, utilizing a wide array of data including weather variability, unit reliability, fuel availability, and market conditions to model hourly system operations and assess the risk and cost of potential capacity shortfalls. Furthermore, resource adequacy assessments are evolving to include advanced capacity accreditation methods like perfect capacity (PCAP) and ELCC, which more accurately reflect the reliability contributions of VERs. For instance, one ELCC study increased solar peak credit from 50% to 89% for certain solar capacity. No significant changes have been made to reserve margin modeling or resource procurement processes since the previous LTRA, and none are planned for the next decade regarding resource adequacy planning, though input assumptions are regularly updated.

Despite maintaining adequate reserve margins, energy risk assessments highlight an important nuance: reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also crucial. Results from these assessments may prompt policy updates or recalibrated targets for PRM policies to better align with actual risk levels identified across the year, including non-peak hours. To address identified capacity needs or potential shortfalls, the IRP process leads to procurement actions approved by regulatory commissions. New resource technologies are selected based on their technical, economic, and capacity attributes. For example, one utility intends to maintain its 15% reserve margin by incorporating potential capacity purchases of up to 370 MW to serve anticipated data mining loads over the next four years, alongside plans to add solar and battery resources in 2029. Overall, planning entities consistently update their capacity expansion plans annually to meet load requirements and adhere to these PRMs.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy risk assessments in the Southeast assessment area utilize a combination of deterministic and probabilistic methods to identify and address potential energy shortfalls across various planning horizons. These assessments incorporate crucial assumptions about fuel availability, generation outages, extreme weather events, and transmission capabilities. Winter peak hours have been identified as the highest-risk period for energy shortfalls, driven primarily by volatile peak demand during extreme cold weather events that exceeds forecasts, and sustained overnight load where demand remains high throughout the evening and early morning, eliminating traditional off-peak troughs. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours.

A significant finding from these assessments is that fuel availability, particularly for natural gas, presents a risk, especially in systems with limited renewable penetration. Entities are mitigating this by securing firm pipeline transportation contracts for baseload plants and ensuring onsite fuel storage (natural gas or fuel oil) for peaking units. Probabilistic modeling, including Monte Carlo simulations, evaluates the impact of these drivers, calculating metrics such as LOLE and EUE; these studies show increased risk in winter and significant EUE increases under fuel-constrained scenarios. Crucially, the results underscore that reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also vital.

Furthermore, scenarios modeling low hydro output and low solar generation during high-demand periods (especially in winter or prolonged cloudy conditions) indicate increased energy risks when variable energy resources (VERs) underperform. While annual production cost simulations performed in an “island” mode (excluding market purchases) have not identified energy deficiencies under base conditions, the RMS provides a comprehensive probabilistic analysis of hourly energy adequacy by simulating thousands of scenarios and considering historical weather, load, solar availability, fuel constraints, and generator outages. The RMS also assesses regional interdependency risks, finding that transmission constraints can hinder economic and emergency imports, exacerbating local energy shortages during widespread events. Energy risk assessments reflect a maturing focus on year-round, all-hour reliability, emphasizing risks from fuel supply chains, weather variability, and the increasing integration of variable renewable energy sources. These findings may lead to policy updates or recalibrated targets for PRM policies (e.g., 15% summer/25% winter) to better align with actual identified risk levels.

ProbA Results

SERC-Southeast does not show any loss of load risk for the year 2027, the EUE is 0.00 MWh and LOLH is also 0.00 hours. For the year 2029, there is a small ANNUAL risk of 0.39 MWh and 0.001 hours.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0.0	0.4
NEUE (ppm)	0.00	0.00	0.001
LOLH (hours per Year)	0.00	0.00	0.001
* Provides the 2024 ProbA Results for Comparison			

The figure below shows the EUE as a Heat Map for the year 2027.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

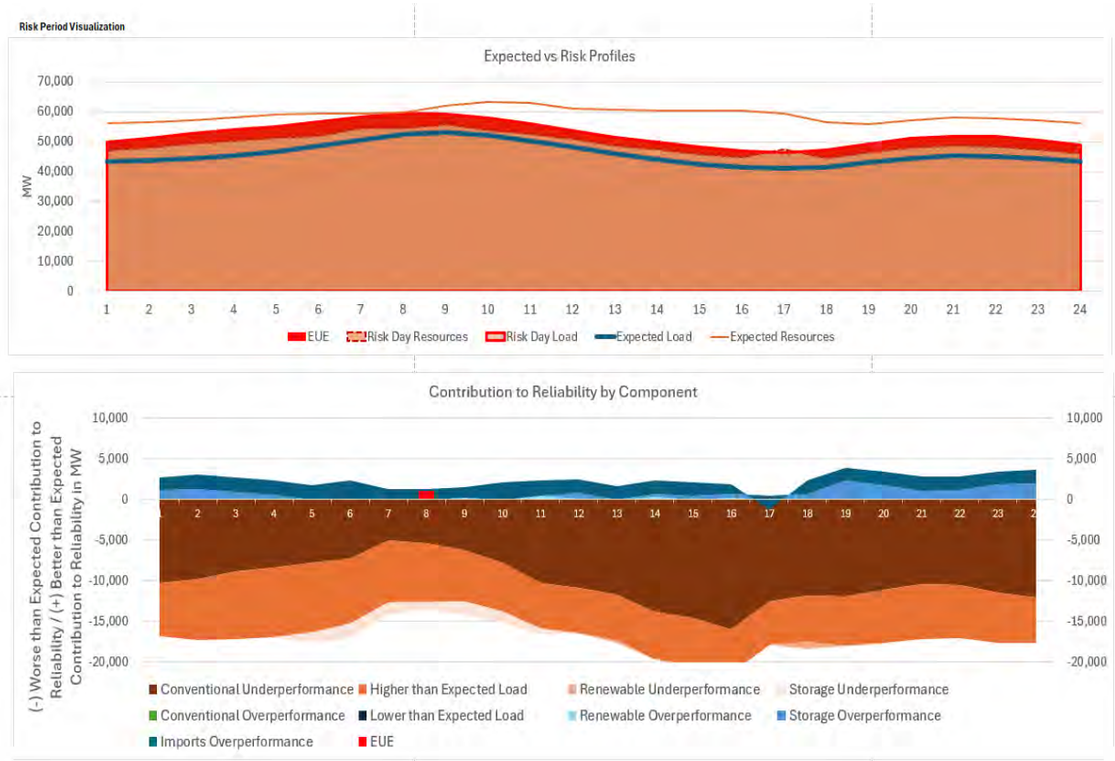
2027 EUE Heat Map

For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events such as weather years 1982, 1985, and 2022, contribute to risk in winter mornings (7:00-8:00 a.m.) and nights (10:00 p.m.-12:00 a.m.). December shows the most risk, followed by January.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	29%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	22%	0%

2029 EUE Heat Map

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1000 event or higher probability, so the event day with the highest EUE in an hour was selected. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029.



The top figure compares the event day to a typical day in December, with weather year 1985, which was an extreme cold event. The lower figure shows the loss of load between 7:00-8:00 a.m. when the load is higher than projected, solar generation is unavailable, energy storage and imports are available during the risk hour.

Between 2027 and 2029, SERC-Southeast is expected to add battery and solar generation Tier 1 resources. The addition of solar generation, however, would not help alleviate risk that occurs in winter morning or winter night hours when solar irradiation is unavailable. Georgia Power Company has publicly filed their intent to build company owned combined cycle, battery energy storage systems, hybrid solar and battery energy storage systems, coming online between 2029 and 2031. However, the commission has yet to vote on approval, expected to do so in December and are not included in the model. SERC-Southeast is not expected to retire additional generation during this time.

SERC-Southeast is seeing high load growth. Between summer 2027 and 2029, there is expected to be an addition of 4,468 MW of summer load and 2,134 MW of winter load.

With the growing dependence on natural gas as the predominant energy source in the SERC Southeast subregion, fuel diversity could become an area of future concern.

Demand

The entities in the Southeast assessment area employ a robust approach to developing their load forecast for the LTRA. This methodology combines econometric modeling, statistically adjusted end-use (SAE) analysis, and hourly bottom-up aggregation across members. Forecasts are annually updated based on historical data and the latest S&P Global economic outlook, using regression models that account for weather, economic indicators, population, appliance efficiency, and load shapes. Both coincident and non-coincident peak demand forecasts are included and refined using specialized tools. LFU is addressed by testing load levels ranging from 80% to 104% of projected peak demand, with weather identified as the primary driver of variability. While DERs like rooftop solar currently have minimal impact, their potential effects are considered in sensitivity scenarios. No major changes have been made to the core forecasting methodology since the prior LTRA, though input assumptions are regularly updated.

Several factors contribute to the 10-year forecasted demand and energy growth rates. Data centers are a significant and highly uncertain consideration, capable of substantially increasing demand when included as a sensitivity in reliability studies, with nearly 400 MW of data mining load expected by 2025. These loads often exhibit unpredictable behavior, with some shifting to 24/7 operation, flattening the overnight load curve and extending peak periods, which complicates traditional peak-centric planning. Large commercial and industrial loads are expected to contribute to energy growth in specific economic development areas. Electrification trends are emerging slowly, with limited current impact on forecasts, though home heating electrification is notably contributing to increased winter peak sensitivity. Beyond the 10-year horizon, transportation electrification is anticipated to become a more significant driver of load growth. The influence of climate change and extreme weather on load forecasting is modest in most cases, with some utilities refining models to reflect more frequent cold weather patterns. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours. EE improvements are occurring but are not yet deemed a significant overall impact, and flexible or price-sensitive loads are typically modeled on the supply side, thus excluded from direct demand forecasts.

Demand-Side Management

Depending on the entity, DSM could be a voluntary DSM water heater program, which allows for limited control of appliance usage during peak demand periods, with the number of installed control switches tracked monthly to forecast future participation. Load research data is used to estimate the diversified load contribution from these devices. While the entity is monitoring how new EE regulations may impact program effectiveness and developing a DSM measurement and verification (M&V) framework, its analysis currently relies on historical load research data. DR resources under contract are monitored and dispatched, and annual ELCC simulations determine the capacity value of each active DR program. BTM DERs are accounted for within annual load forecasts, while front-of-the-meter (FTM) DERs are treated as generation assets. The entity is also exploring new DR and flexibility programs, including pilot efforts in commercial and industrial automated DR and solar-plus-storage, and implementing a DERMS to enable broader coordination. No modifications to DR methodologies or assumptions have been made since the *2024 LTRA*, but new pilot programs and system capabilities are actively being developed. For EE and conservation, no significant changes have occurred in measurement or accounting since the prior LTRA. EE impacts are generally incorporated through adjustments to load forecasts based on federal and state efficiency standards, appliance saturation trends, and building code updates, reflected in econometric models or end-use forecasts that estimate reduced energy consumption over time.

Distributed Energy Resources

The estimated penetration of DERs in the Southeast assessment area remains modest, with forecasts projecting 1–1.5% of peak load over the next five years and staying below 2% over a 10-year horizon. Specifically, BTM solar PV is expected to grow from 57 MW by 2030 to 120 MW by 2035. Currently, DERs and rooftop solar are considered to have minimal impact on overall reliability, with no emerging transmission or resource adequacy issues directly attributed to them anticipated for Summer 2025.

In terms of planning, BTM DERs are accounted for within annual load forecasts and are not explicitly modeled as discrete capacity resources. Instead, they are represented using hourly generation profiles to account for operational factors like ramping, and estimated generation is placed back onto load buses when installations reach or exceed 2 MW. Conversely, FTM DERs are treated as generation assets. While BTM solar is contributing to energy availability and reducing fossil fuel consumption, their limited capacity value and variability are creating challenges, particularly during the sunrise and sunset hours, requiring greater flexibility from non-solar resources. Solar-related ramping concerns and energy adequacy under evolving weather conditions are considered emerging reliability challenges, which are actively being studied through triennial renewable integration studies. Load forecast uncertainty related to DERs is addressed by considering their potential effects in sensitivity scenarios, such as assuming zero DER contribution under stress conditions.

Generation

The Southeast assessment area actively manages its generation portfolio to ensure reliability amid a changing resource mix, with particular focus on the increasing integration of utility-scale solar and other VERs. While current renewable penetration is modest, leading to no significant stability or inertia issues observed to date, future challenges like intra-hour volatility and ramping needs are being proactively evaluated. The Renewable Cost and Benefit (RCB) Framework is utilized to assess integration costs and identify mitigation strategies such as flexible backup resources.

Regarding net demand ramping, the assessment area does not currently identify any emerging issues due to the limited penetration of VERs and a robust, flexible generation portfolio primarily composed of natural gas units. Annual analysis of five-minute ramping data is conducted to inform regulating reserve requirements, and existing natural-gas-fired units, supported by firm fuel supply and fuel-switching capabilities, are deemed sufficient to meet current and projected ramping needs.

Capacity contribution values for VERs like solar and wind are determined using a combination of historical performance data and ELCC analyses via the SERVM reliability and production cost model. For solar, contributions are initially set at 50% of nameplate capacity during May–September, with annual re-evaluation based on actual performance, though no contribution is assigned in winter due to the assessment area's winter peak planning season. An ELCC study in 2024 notably increased solar peak credit for up to 340 MW of solar capacity. While energy storage resources are evaluated through ELCC, with a preferred minimum duration of two hours, no operational storage resources are currently on the system. Hydro resources are credited at 100% due to firm delivery contracts.

Efforts to address IBR performance issues include enhanced interconnection studies that assess various factors like thermal loading, voltage stability, and short circuit performance. EMT models are now required from Generator Owners to better simulate and understand IBR behavior during disturbances, and mitigations include adjusting ramp rates and enforcing ride-through requirements. Additional phasor measurement units (PMU) are being deployed to enhance real-time situational awareness, particularly at IBR interconnection points. While current IBR penetration is low, network impacts and protection coordination are identified as the primary reliability concerns being addressed.

Generator retirements have seen no changes to confirmed or unconfirmed projections since the *2024 LTRA*, with no unit retirements currently projected over the 10-year planning horizon. All native generation, including coal, natural gas, and nuclear resources, is expected to remain available to meet peak demands. Planning entities have established processes involving detailed studies over a 10- to 20-year horizon to assess potential reliability impacts of retirements, considering mitigations such as transmission infrastructure capital improvements or dynamic VAR support. The IRP process coordinates retirement schedules with the addition of replacement capacity to prevent reliability gaps.

Natural gas fuel supply risk is actively managed, with approximately 78% of winter on-peak natural gas generation capacity having either firm fuel supply arrangements or backup fuel options like oil or dual-fuel capability. Annual gas pipeline failure studies are conducted ahead of each summer and winter season to assess impacts under various curtailment scenarios. Communication protocols between electric system operators and natural gas operators are maintained for coordinated responses. Long-term planning processes incorporate fuel risk through load capability analysis and production cost modeling over a 20-year horizon, ensuring capacity plans meet PRMs.

Energy Storage

While there are currently no operational energy storage resources on the system in the Southeast assessment area, future plans do include the addition of solar and battery resources by 2029. BESS are recognized as IBRs that, like solar, require different modeling and analysis techniques compared to traditional synchronous generation. The uncertainty surrounding the future locations and generation outputs of new BESS is noted as a factor that complicates proactive planning.

For planning purposes, energy storage resources are primarily evaluated for their capacity contribution through ELCC analyses. A preferred minimum duration of two hours is considered for operational reliability when evaluating energy storage resources, although there is no formal duration requirement currently enforced. Pilot programs are also being explored, specifically solar-plus-storage initiatives, as new DR and flexibility programs. These programs aim to provide flexible capacity and fast-start capabilities to the system.

No major methodology modifications have been made to the methods or assumptions for incorporating energy storage since the *2024 LTRA*.

Capacity Transfers

Capacity transfers are important for reliability in the Southeast assessment area and the SERC Region. System adequacy is maintained through planning studies and coordination with neighbors to manage evolving energy needs and maintain regional reliability.

Currently, surplus capacity for transfer and delivery is anticipated to remain available to meet reliability margins and support marketing opportunities. Transmission flow patterns are becoming more dynamic due to shifts in internal and external resource portfolios, retirements, additions, and system topology adjustments, but no significant impacts to firm transmission contracts have been

identified to date. Furthermore, recent reserve margin studies suggest that current transmission capabilities do not pose a constraint on resource adequacy within the assessment area.

To facilitate and ensure reliable capacity transfers, the assessment area engages in extensive coordinated efforts, studies, and protocols with neighboring assessment areas for both peak and non-peak hours. These coordinated efforts include:

- **Joint Transmission Planning Studies**, such as the Southeast Regional Transmission Planning (SERTP) process, which evaluate the BPS's ability to support transfers under various seasonal and system conditions, accounting for projected load growth, generation changes, and transmission upgrades.
- **Firm Transfer Agreements and Modeling**, which are integrated into seasonal and long-range planning studies to ensure deliverability under normal and contingency conditions. These agreements are regularly reviewed and updated.
- **Seasonal Coordination Studies**, including power flow, stability, and transfer capability analyses, conducted prior to each summer and winter season to assess the ability to maintain reliability and meet transfer obligations under expected and extreme conditions.
- **Contingency and Emergency Protocols** with neighboring BA and Reliability Coordinators to support emergency situations and real-time transfers. These protocols are exercised through reliability drills and supported by tools like dynamic line ratings and real-time data sharing.
- **Reserve Sharing and Balancing Arrangements** that enable entities within the assessment area to share generation reserves during system events or peak demand periods, supporting both operational reliability and economic efficiency.
- **Real-Time Operational Coordination** where neighboring areas monitor real-time flows and manage congestion through dynamic scheduling, redispatch strategies, and curtailment procedures as necessary.
- **Coordinated use of the Open Access Same-Time Information System (OASIS)** to ensure transparency and proper scheduling of transfers, preventing violations of reliability standards or operational issues.

Despite these robust coordination mechanisms, energy risk assessments have highlighted certain limitations regarding external reliance, particularly during extreme conditions. Studies, including the RMS, have modeled interactions with 13 neighboring systems to understand the limits of market support during high risk periods. These assessments indicate that regional transmission constraints can hinder economic and emergency imports, potentially exacerbating local energy shortages during widespread events. Furthermore, studies suggest limited excess market generation availability during extreme weather events in the Southeast, underscoring the critical importance of internal resource adequacy planning.

In terms of future reliance, while the overall trend suggests sufficient internal capacity, one utility expects to potentially make capacity purchases of up to 370 MW to serve possible data mining loads over the next four years. This indicates a willingness to utilize external purchases to meet specific, potentially high-density and unpredictable, new loads. The results of energy risk assessments are used to inform capacity expansion plans and determine the need for additional capacity purchases.

Transmission

Entities within the assessment area have numerous transmission projects planned or underway over the next 10 years to support system reliability and address evolving load and generation needs. These projects include approximately 1,308 miles of new transmission lines above 100 kV, 1,322 miles of line rebuilds, around 20 reactive compensation installations, 50 new transmission stations, and various upgrades to increase the capacity of existing infrastructure. One entity plans to retire a 46 kV transmission path and convert affected delivery points to 115 kV service, constructing a new network line to address localized thermal constraints and improve contingency performance. Power electronic devices such as reactive compensation systems are being installed to enhance voltage stability and system performance. While no major transmission adequacy issues have been identified, there are risks of project delays due to supply chain disruptions and contractor availability. Mitigation measures include staggered project timelines, strategic inventory management, and evaluation of interim technologies like variable line impedance devices. Overall, the assessment area maintains a coordinated and proactive transmission planning approach to ensure continued reliability across the region. Since the *2024 LTRA*, planning entities across the assessment area have begun implementing or exploring several enhancements to their transmission planning processes in response to evolving reliability, resource mix, and regulatory conditions. One key area of focus is the growing presence of IBRs, such as solar and battery storage, which require different modeling and analysis techniques compared to traditional synchronous generation. Entities are now incorporating additional scenarios into their long-term planning to assess the adequacy of the transmission system under various levels of IBR penetration, particularly in areas experiencing rapid deployment of utility-scale renewables.

Another significant development involves planning for large data center loads, which present unique challenges due to their high energy consumption and sensitivity to power quality. Entities are preparing to implement new technical studies—such as dynamic modeling and harmonic analysis—to ensure that these loads can be reliably served without compromising grid stability. These studies are expected to become increasingly important over the next 10 years as data centers proliferate across the region. While there have been no wholesale changes to core transmission planning methodologies, adjustments are being made to better reflect recent operating experiences. For

example, entities have refined the load levels used in extreme case scenarios to align more closely with observed peak events. There is also growing interest in performing comprehensive gas-electric interdependency studies to assess the risks posed by natural gas supply disruptions to gas-fired generation resources.

For non-FERC-jurisdictional entities, FERC Order No. 2023 is being monitored, and although compliance is not mandatory, potential alignment with its principles—such as improved generator interconnection procedures and enhanced transparency in queue management—is being considered.

Regional coordination remains a critical component of transmission planning. Entities continue to work closely with first-tier neighbors through long-term, quarterly, and weekly coordination protocols. Interface transfer capabilities are calculated regularly on monthly and two-day-out bases, with requests managed through the OASIS system. Coordination of transfer capability assessments and planning assumptions is also carried out through interregional forums, such as the SERC Long-Term and Near-Term Working Groups and the Southeastern Regional Transmission Planning process. These efforts ensure that planned projects and operational practices are aligned across the region, helping to maintain reliability as system conditions evolve.

Reliability Issues

The Southeast assessment area actively manages its generation portfolio to ensure reliability amidst a changing resource mix. While no significant stability or inertia issues have been observed to date due to the current modest renewable penetration, several evolving reliability concerns are being proactively addressed:

- **Elevated Winter Energy Risk and Sustained Overnight Loads**: Energy risk assessments consistently identify winter peak hours as the highest-risk period for energy shortfalls. This increased risk is driven by two primary factors: volatile peak demand due to extreme cold weather events exceeding forecasts, and sustained overnight load where demand remains high throughout the evening and early morning. Recent winter events, such as Winter Storm Elliott, have led to updated load shapes that reflect higher and more sustained loads, underscoring the importance of energy adequacy beyond just peak periods. This indicates a shift requiring more continuous energy coverage rather than just peak-hour capacity.
- **Natural Gas Fuel Supply Vulnerability**: Fuel availability, particularly for natural gas, has emerged as a significant energy risk. To mitigate this, entities in the assessment area actively manage natural gas fuel supply risk through firm fuel arrangements, backup capabilities like onsite fuel storage or dual-fuel options (e.g., oil), and annual gas pipeline failure studies conducted before each summer and winter season. Communication protocols are also maintained between electric and natural gas system operators for routine and contingency operations. Long-term planning studies also incorporate considerations for gas production limitations and transportation bottlenecks.
- **Challenges Posed by Large Industrial and Commercial Load Additions**: The assessment area is experiencing an increasing demand of large industrial and commercial load additions, such as data centers and crypto mining facilities, which require enhanced coordination, especially with local distribution cooperatives. These loads can “substantially increase demand” and exhibit unpredictable behavior, with some shifting to 24/7 operation and relying on short-term capacity purchases. Entities are proactively developing updated technical interconnection requirements and pursuing regulatory approvals to procure additional generation to serve these new loads.

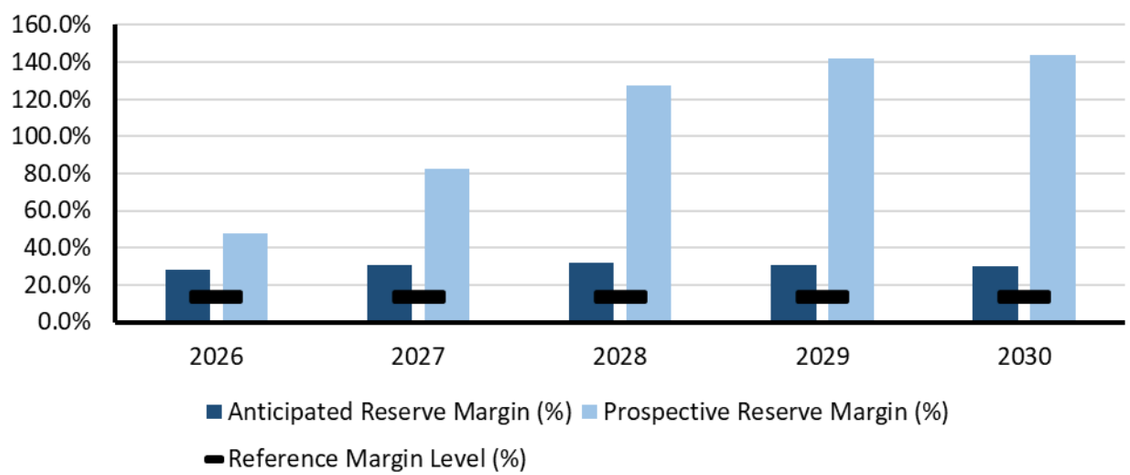


Texas RE-ERCOT

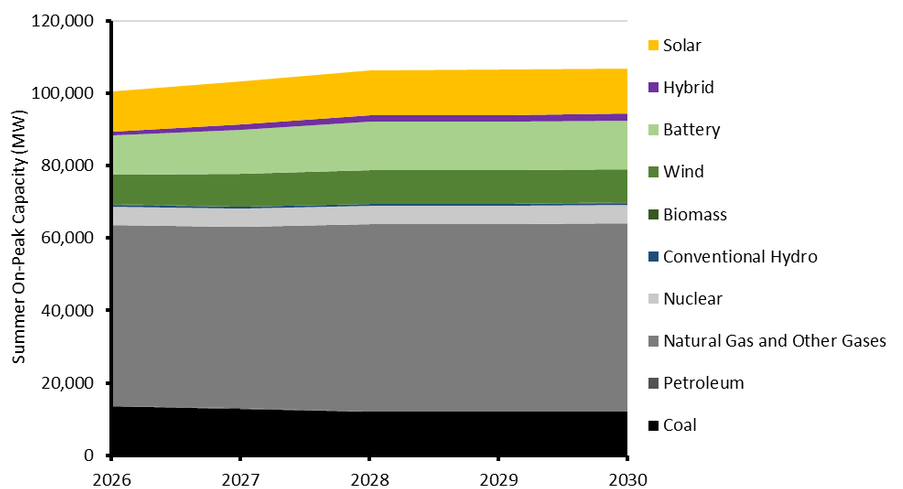
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Reliability Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	94,650	104,295	121,543	128,851	138,944	144,522	148,567	149,846	152,230	154,077
Demand Response	13,346	22,127	37,672	43,888	53,131	57,720	60,942	61,846	62,644	63,321
Net Internal Demand	81,304	82,168	83,871	84,963	85,813	86,802	87,625	88,000	89,586	90,756
Additions: Tier 1	10,377	15,216	18,527	19,037	19,037	19,037	19,037	19,037	19,037	19,037
Additions: Tier 2	15,391	42,413	79,923	95,374	98,707	99,018	99,018	99,018	99,018	99,018
Additions: Tier 3	5,022	17,546	36,405	51,080	58,217	58,217	58,463	58,463	58,463	58,463
Net Firm Capacity Transfers	508	659	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122
Existing-Certain and Net Firm Transfers	93,870	92,008	92,046	92,113	92,401	92,401	92,401	92,401	92,401	92,401
Anticipated Reserve Margin (%)	28.2%	30.5%	31.8%	30.8%	29.9%	28.4%	27.2%	26.6%	24.4%	22.8%
Prospective Reserve Margin (%)	47.9%	82.3%	127.3%	142.1%	143.9%	141.5%	139.2%	138.2%	134.0%	131.0%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Texas RE-ERCOT Highlights

- The ARM is above the 13.75% RML for all years and seasons and reflects the inclusion of provisional forecast estimates of large-load curtailment potential, applicable before and during ERCOT emergency conditions.
- ERCOT forecasts total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%.
- Texas Senate Bill 6, signed into law in June 2025, provides ERCOT with new large-load curtailment management tools and the authority to direct large loads to curtail their load both prior to and during declared energy emergency situations.
  - Offsetting the positive ARM impact of these load management programs is the switch from using historical average on-peak capacity factors to average ELCC for IBRs.
- ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026, growing to 25.2 GW by 2029, which reflects the furthest future year for reported planned commercial operations dates.
- ERCOT's 2024 Regional Transmission Plan (RTP) includes a 345 kV plan and the Texas 765 kV Strategic Transmission Expansion Plan (TX 765-kV STEP), which addresses unprecedented load growth expected by 2030.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	13,596	12,941	12,156	12,156	12,156
Coal*	13,596	12,550	11,205	11,205	11,205
Petroleum	30	30	30	30	30
Natural Gas	50,032	50,122	51,689	51,689	51,977
Natural Gas*	50,032	49,764	51,331	51,331	51,619
Biomass	131	131	131	131	131
Solar	11,049	11,923	12,305	12,534	12,534
Wind	8,303	8,900	9,215	9,219	9,219
Conventional Hydro	570	570	570	570	570
Nuclear	4,973	4,973	4,973	4,973	4,973
Hybrid	1,127	1,497	1,813	1,909	1,909
Battery	10,734	12,285	13,375	13,374	13,374
Total MW	**100,545**	**103,372**	**106,257**	**106,584**	**106,872**
Total MW*	**100,545**	102,203	104,528	104,855	105,143

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.
**Wind, solar, and battery capacities are based on their projected effective load carrying capabilities during peak load conditions.

Planning Reserve Margins

The ARM is above the 13.75% RML only for summers 2026 and 2027, and winters 2025–26 and 2026–27. The main contributing factor for lower ARMs relative to last year's LTRA is the switch from using historical average on-peak capacity factors to average ELCC for IBRs. In the case of solar, ELCCs are significantly lower than on-peak capacity factors since ELCCs reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low. Partially offsetting the reduction in solar contribution was the shift from assigning 0% on-peak capacity contribution for battery energy storage to using average ELCCs based on design duration. For example, battery storage systems with a duration of one hour or less are assigned an ELCC of 36%, whereas the ELCC for systems greater than one hour and less than two hours is 69%.

Energy Risk, Including Non-Peak Hour Risk

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at HE 9:00 p.m.—based on probabilistic capacity reserve modeling for monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. However, the large growth in battery energy storage resources and associated changes in state of charge management have mitigated the capacity reserve scarcity risk relative to previous years. For winter, risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 to 9:00 a.m.) as well as the early evening hours.

Probabilistic Assessments (NERC ProbA and Other Studies)

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	11,090	5,864	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.94	3.64
*** Provides the 2024 ProbA Results for Comparison**			

Like the 2024 ProbA Study, most risk is in the winter, and this is mainly driven by the large demand variability modeled in the winter. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year.

12x24 EUE Heat maps (months for the vertical axis, hours for the horizontal axis) for 2027 and 2029 are provided below. Note that as the numbers are given in percentages, the lower winter values in 2029 relative to 2027 do not indicate a decrease in winter risk, just a smaller portion of the annual total.

2027

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	4%	3%	2%	2%	3%	5%	8%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	7%	5%	4%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	2%	2%	2%	2%	2%	3%	4%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	4%

2029

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	3%	2%	2%	2%	3%	4%	6%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	4%	4%	4%	3%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	1%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%	5%	1%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	1%	1%	1%	1%	1%	2%	2%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	2%	2%	2%	2%

Demand

ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads, comprised mostly of data centers. The breakdown of new large loads added by 2030 by customer classification is as follows:

Load Additions in the Load Forecast (MW) (Cumulative)			
Load Type	**End of Year 2 (2027)**	**End of Year 5 (2030)**	**End of Year 10 (2035)**
Data Centers	**6,700**	**23,000**	**25,000**
Cryptocurrency Mining Facilities	**4,500**	**7,500**	**8,500**
Hydrogen Electrolysis	**3,000**	**7,902**	**9,100**
Industrial Manufacturing Load	**2,800**	**7,100**	**7,600**

For 2025, the ERCOT transmission service providers (TSP) had once again reported a significantly larger-than-normal amount of contracted large loads that they asked to be included in the *2025 Long-Term Load Forecast* and *Regional Transmission Planning Study*. Due to the large amount of large-load requests for 2025, ERCOT has applied adjustment factors to these requests. ERCOT has adjusted the large-load projections provided by the TSPs based on the patterns observed by recent projects. The first adjustment was based on the average project delay of 180 days from the original project requested energization date for projects with in-service dates in 2022 through 2024. The next adjustment was applied to Data Centers. ERCOT studied requested MWs versus the peak consumption by data center site for data centers with in-service dates in 2022 through 2024. The average peak consumption per site was 49.8% of the requested MW. This factor was applied to all non-crypto data center load additions. The final adjustment used the percentage of previously filed officer letter projects with in-service dates in 2024 that have energized (55.4%). This percentage is based on percentage of loads energized.

The PUCT is developing criteria for including large loads in ERCOT's load forecasts along the lines of criteria applicable to generation projects (for example, the large-load customer has executed and securitized an interconnection agreement or meets other criteria demonstrating a firm commitment to interconnecting the load).

Demand-Side Management

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT's authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. The following table shows the total large loads and their curtailment amounts included in the "Controllable and Dispatchable Demand Response" line items.

Summer	Total LL (MW)	LL Curtailment (MW)		Winter	Total LL (MW)	LL Curtailment (MW)
2025 (S)	3864.4	1,313.9		2025-26 (W)	9112.9	8,227.7
2026 (S)	12355.4	8,853.5		2026-27 (W)	17289.8	15,909.3
2027 (S)	21665.7	17,171.5		2027-28 (W)	31590.8	29,408.9
2028 (S)	38583.3	32,716.5		2028-29 (W)	45249.3	42,298.1
2029 (S)	45681.1	38,932.6		2029-30 (W)	55533.1	51,981.4
2030 (S)	55964.9	48,175.5		2030-31 (W)	60917.9	57,010.6
2031 (S)	61349.7	52,764.3		2031-32 (W)	64863.6	60,672.7
2032 (S)	65295.4	55,985.9		2032-33 (W)	66370.5	62,017.8
2033 (S)	66802.3	56,890.6		2033-34 (W)	67764.7	63,256.0
2034 (S)	68196.5	57,688.4		2034-35 (W)	69032.1	64,373.6
2035 (S)	69463.9	58,365.6		2035-36 (W)	69805.1	65,043.3

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member Transmission and Distribution Service Providers (TDSPs) to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

ERCOT has proposed rule changes mandated by the Texas Legislature to establish a process to collect comprehensive data from Distribution Service Providers for so called "Unregistered Distributed Generators" (primarily rooftop solar systems). The data will be collected on a substation level and will include information to be used for network modeling and analysis, including aggregate reactive power capability and status of PUCT voltage/frequency ride-through requirements.

Generation

In 2024, ERCOT received notices of suspension of operations for three gas-steam units in the San Antonio area. Reliability impact studies indicated that all three were needed to manage the South Texas Interconnection Reliability Operating Limit (IROL) established in 2024. As a result, ERCOT signed

a two-year "Reliability Must Run" (RMR) agreement with CPS energy for one of the three generators (Unit 3). This generator, as part of its RMR service obligation, would only operate when necessary to provide voltage support, stability, or management of localized transmission constraints when a market solution does not exist. ERCOT also signed a contract in June 2025 to use 15 mobile generators that are being relocated from Houston to the San Antonio area. The contract ends in March 2027 when transmission solutions are expected to be in place to offset the loss of the mothballed CPS generating units.

New rules became effective in October 2024 to improve IBR ride-through performance and monitoring and mitigation efforts. The rules were developed in response to NERC recommendations following IBR failures during system disturbances in West Texas. The new ride-through requirements align with the specifications of the updated IEEE 2800-2022 standard, which addresses the interconnection and interoperability of IBRs. As part of the new rules, IBR entities are required to maximize their IBR ride-through capabilities, which includes making software, firmware, and settings adjustments, and potentially physical modifications to ensure that they can remain connected to the grid during frequency and voltage disturbances. The rules also establish a process for investigating, reporting, and mitigating ride-through performance failures, requiring resource entities to develop mitigation plans within a defined timeline. IBR entities must meet the new requirements by December 31, 2025, or their synchronization date, subject to an extension/exemption process.

During 2024, units totaling 18.6 MW were retired, comprising a 9.6 MW biomass facility, a 7 MW wind site, and 2 MW battery storage system. So far in 2025, a 62 MW gas combined-cycle unit was retired.

Energy Storage

ERCOT expects battery energy storage capacity to reach 18.9 GW by summer 2026 (Existing and Tier 1 resource categories). The capacity grows to 25.2 GW by 2029, which reflects the furthest future year for planned commercial operations dates reported by project developers.

ERCOT is moving away from a dual to an integrated single model of an energy storage resource for operational and transmission planning studies. Under the dual approach, an energy storage resource is composed of a generator with a negative minimum power to represent consumption and a generator with a positive maximum power to represent injection. The single "integrated" generator model, along with other system enhancements for battery energy storage, is being implemented as part of ERCOT's "Real Time Co-Optimization + Battery" project, expected to be implemented by December 2025. Since each resource receives independent dispatch instructions and ancillary service deployments in the dual model approach, moving to a single integrated resource model will eliminate current performance monitoring issues. The discharging behavior for all energy storage resources is considered for peak cases in transmission planning studies. The charging behavior for all energy storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources, if required to provide voltage support, need to have the reactive power capability be available at all MW levels when charging or discharging and meet the voltage ride-through requirements to remain connected to the system. To support larger penetration levels of energy storage resources, new rules have been implemented to improve state-of-charge monitoring in energy dispatch and Reliability Unit Commitment.

Capacity Transfers (Reliance on Assistance)

ERCOT has coordination plans in place with neighboring grids. These plans cover DC tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers. For its transmission planning studies, ERCOT tests the outage of each of the ERCOT-SPP DC ties, plus a contingency on top of that, to ensure no reliability issues post-contingency. There are no severe scenarios studied where multiple DC ties are assumed to be unavailable.

Transmission

ERCOT's 2024 RTP includes a 345 kV plan and a 765 kV plan, called the Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP). The 765-kV plan tackles the unprecedented load growth expected by 2030 and associated regional planning challenges and addresses existing congestion issues. TX 765-kV STEP enhances transfer capability by an additional 600 to 3,000 MW across various scenarios evaluated in the analysis and would also increase the West Texas export stability constraints. The 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers. Overall, 274 reliability projects were identified in the 2024 RTP's 345 kV plan to address all reliability violations compared with 173 projects in the 2023 RTP, 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP. This upward trend reflects grid infrastructure needed to support rapidly growing power demands and an evolving generation resource mix.

ERCOT is adopting changes to its planning processes to address the long-term transmission challenges. Examples of the major changes include establishment of a new congestion cost savings test for economic project evaluation, establishment of resiliency criteria for the ERCOT region, and development of new multi-value criteria to address the process for determining whether a project that addresses a resiliency issue provides sufficient benefit balanced with economic savings or reliability benefits.

Reliability Issues

There are several reliability concerns associated with the rapid growth in large loads:

Loss of Load: Due to the amount of large electronic-based load projected to energize in upcoming years (mainly from cryptocurrency mining facilities), ERCOT is concerned that potentially thousands of megawatts of load can instantly drop or switch to backup generation during normally cleared system faults, thereby posing significant risks to system reliability. To address this concern, ERCOT has proposed a change to its Reliability Performance Criteria to limit load loss for any single contingency and to specify how loss of load is calculated for this criterion. ERCOT recently completed a Load Loss Threshold Analysis that indicates that the load loss should be limited to 2,600 MW.

Load Forecasting Challenges: The flexible operation of large loads also presents challenges for accurate load forecasting and monitoring. ERCOT has observed increasing errors in its load forecasts, which is problematic during extreme or unusual operating days when having an accurate forecast is most critical for maintaining reliability. New approved rules include standards for the identification and classification of a site with an aggregate peak demand of 25 MW or more at a common substation in ERCOT's Network Operations Model. Such information will provide ERCOT visibility of the locations of these loads for operational, modeling, and planning purposes.

Potential Subsynchronous Oscillation Vulnerabilities: Large loads, particularly those with high reactive power consumption, can cause subsynchronous oscillation (SSO) that can damage generation and other equipment and ultimately destabilize the grid. This vulnerability is highest in areas with a weak grid, such as West Texas. To address SSO issues, ERCOT is implementing new rules that require SSO vulnerability assessments for large-load customers seeking grid interconnection as well as for transmission projects.

Need for a Large Load Interconnection Study Process: ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

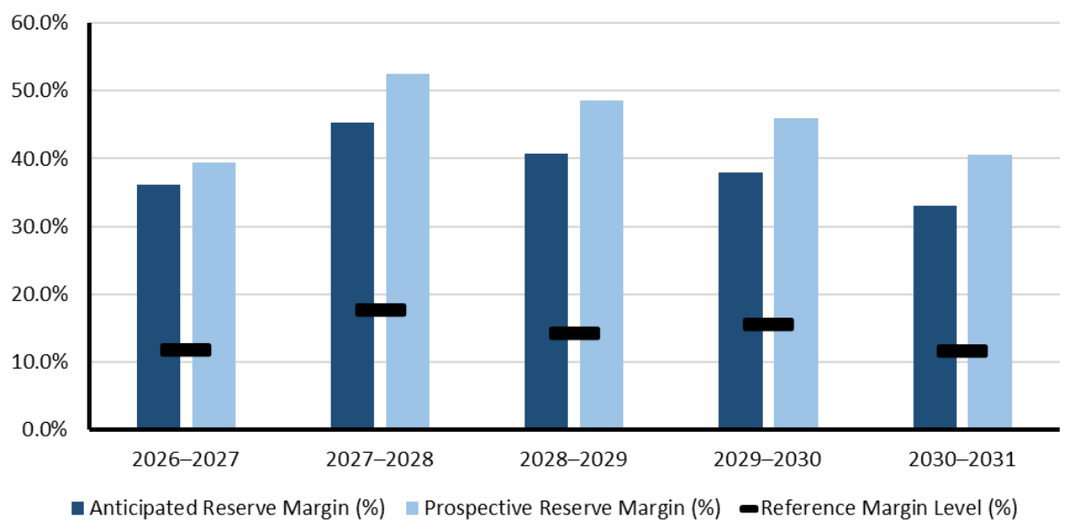


WECC-Alberta

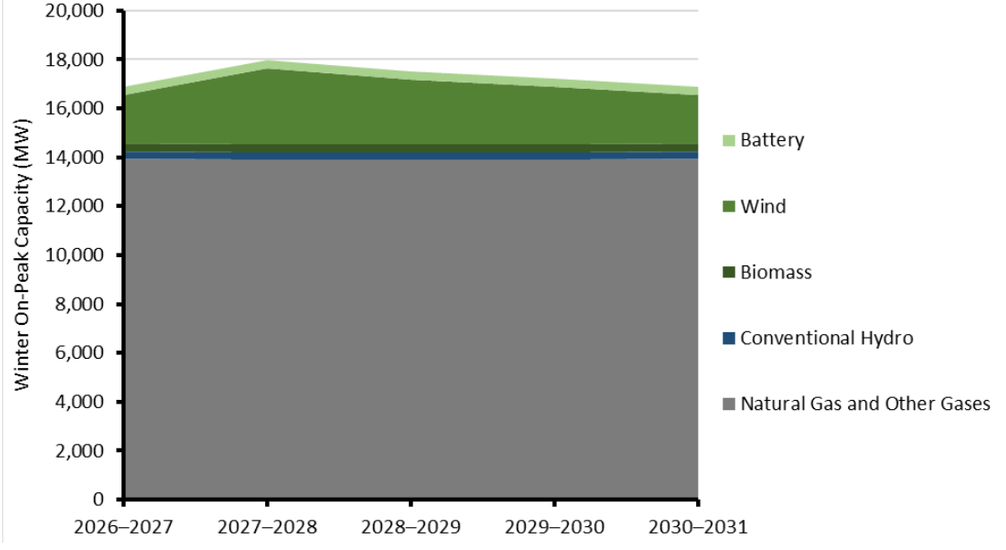
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and Reliability Coordinator responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Additions: Tier 1	209	209	209	209	209	209	209	209	209	209
Additions: Tier 2	393	889	983	1,009	959	1,009	921	971	971	971
Additions: Tier 3	392	658	917	1,297	1,334	1,631	1,635	1,751	1,751	1,751
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	16,764	17,856	17,394	17,074	16,764	17,074	16,502	16,820	16,820	16,820
Anticipated Reserve Margin (%)	36.2%	45.3%	40.7%	38.0%	33.0%	34.7%	29.0%	31.1%	30.2%	26.4%
Prospective Reserve Margin (%)	39.3%	52.4%	48.6%	46.0%	40.5%	42.6%	36.1%	38.5%	37.7%	33.6%
Reference Margin Level (%)	11.8%	17.6%	14.3%	15.6%	11.6%	15.2%	12.2%	14.3%	13.9%	13.5%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Alberta Highlights

- WECC-Alberta's ARM does not fall below the RML during the 2025–2035 time frame.
- WECC-Alberta's total electricity demand is projected to grow by 10% over the next 10 years. Summer peak hour demand is projected to grow by 7%, and winter peak hour demand is projected to grow by 11% over the same period.
- Alberta is anticipated to add 556 MW of Tier 1 gas, solar, and battery resources over the next 10 years. Alberta's thermal power generation fleet is aging, and significant additions of Tier 2 and 3 variable renewable energy resources are being proposed to make up for forthcoming thermal retirements while meeting Alberta's 30% renewable by 2030 policy requirement. On top of the 250 MW of existing storage, 88 MW are anticipated Tier 1 and 370 MW are Tier 2 additions over the next 10 years. Still, rapid declines in solar and wind output could cause ramping issues in the future and require the use of contingent reserves and assistance from the NWPP Reserve Sharing Group.
- AESO has recently added two transmission lines to its system to increase reliability and integrate fossil-fired generation additions.
- Under a different set of assumptions and with a different vintage of data from the LTRA, the NERC ITCS for Canada concluded that WECC-Alberta may have winter energy deficiencies that could be alleviated by increased transfer capabilities.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	13,932	13,908	13,890	13,900	13,932
Biomass	336	336	335	336	336
Wind	2,000	3,109	2,665	2,327	2,000
Conventional Hydro	293	301	301	310	293
Other	81	81	81	81	81
Battery	330	330	329	330	330
Total MW	16,973	18,065	17,602	17,283	16,973

WECC-Alberta Assessment

Planning Reserve Margins
WECC-Alberta's ARM does not fall below the RML during the 2025-2035 time frame. WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1 day in 10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Canada Clean Electricity Regulations (CER) were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Alberta has recently entered into an agreement with the Canadian federal government to pursue alternative policies to achieve a net-zero power grid by 2050.

Energy Risk, Including Non-Peak Hour Risk
AESO uses an hourly probabilistic model to quantify uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation in operational time frames.

ProbA Results

Alberta does not show any LOLH or EUE in 2027 or 2029 and therefore does not have any further reporting or visualizations.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*** Provides the 2024 ProbA Results for Comparison**			

Demand
Alberta's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 7% and winter peak hour demand is projected to grow 11% over the same period. The primary driver for demand growth in Alberta is transportation electrification. Large-load additions in the forecast total 80 MW over the next five years and 105 MW through 2035. Additional large loads that may materialize and are not included in the forecast amount to 1,600 MW by 2030 and 2,100 by 2035.

Seasonally, the region is becoming more dual-peaking with summers almost matching winters.

Demand-Side Management
AESO factors in approximately 250 MW of DSM in its load forecast and this is projected to remain steady across the 10-year assessment period.

Generation
Alberta is anticipated to add 556 MW (nameplate capacity) of Tier 1 gas, solar, and battery resources over the next 10 years. Tier 2 additions include nearly 5 GW of gas, solar, wind and batteries and Tier 3 additions include just over 5 GW of gas, solar, wind, conventional hydro, and batteries. Operational and planning issues related to generation in WECC-Alberta include the following:

- Aging Thermal Resource Fleet: There is ongoing analysis of potentially mothballing aging coal-to-gas boilers. Alberta has five natural gas steam sites over 35 years old, which total 1,745 MW of capacity. Alberta shows significant additions of Tier 2 and Tier 3 solar and wind to make up the difference. Supply shortfalls are addressed using the protocols in AESO's ISO Rules. These protocols include directives such as instructing available assets and long-lead-time assets to deliver energy up to their maximum capability, calling upon DR, and maximizing import capability.
- Solar and Wind Variability: Rapid decline in solar and wind output coupled with off-line thermal resources can create situations in which thermal resources cannot be ramped up in time to counter the loss of renewable generation. The use of contingency reserves coupled with a subsequent grid alert declaration to receive assistance from the NWPP Reserve Sharing Group (NWPPRSG) are options for addressing these situations.
- Electric-Gas Coordination: As a part of WECC's load and resources data request, members were asked to provide a conservative estimate of the percentage of natural gas generating capacity that is likely to have firm supply for 2025 and 2030 for both the summer and winter season. Results indicated that all natural-gas-fired generators connected to AESO's system are fueled through firm gas supply contracts during both the summer and winter seasons but do not report any dual-fuel capacity. To enhance operational reliability of natural gas fuel supplies for the province, Alberta's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events impact the gas supply and transportation system. There is frequent communication between system operators regarding gas resources

that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

- Resource Portfolio, Clean Electricity, and Development Policies: The Canadian province of Alberta is required to ensure its electricity supply is 30% renewable by 2030. Alberta has also issued a ban on renewable energy project development on prime agricultural land and a buffer zone around pristine views, both of which could limit siting for wind and solar. This followed a temporary moratorium from August 2023 to March 2024 on new renewable approvals, creating investment uncertainty. In January 2025, Alberta lifted a previous 2022 moratorium on coal exploration, reopening 190,000 hectares of land to new coal development.

Energy Storage

In addition to the 250 MW of existing energy storage in Alberta, 88 MW are anticipated Tier 1 additions, and 370 MW are projected Tier 2 additions of energy storage over the next 10 years. Storage in the west is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Alberta transmission planning region from all its neighbors, including dc-only interties, is 1,096 MW in 2024 Summer and 1,005 MW in 2024–25 Winter. These values translate to approximately 10% of peak summer load and 9% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Montana (see WECC-Northwest) and British Columbia (see WECC-British Columbia).

The ITCS for Canada further showed that WECC-Alberta may have winter energy deficiencies that can be alleviated with increased transfer capabilities.

Transmission

In 2024, Alberta added two transmission lines for fossil-fired integration. The reported primary driver for transmission expansion in Alberta is reliability.

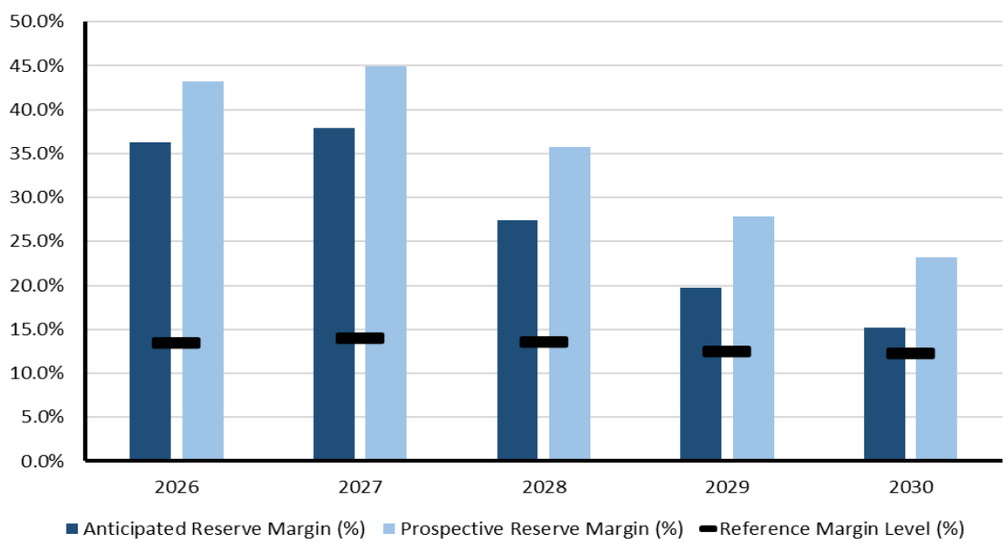


WECC-Basin

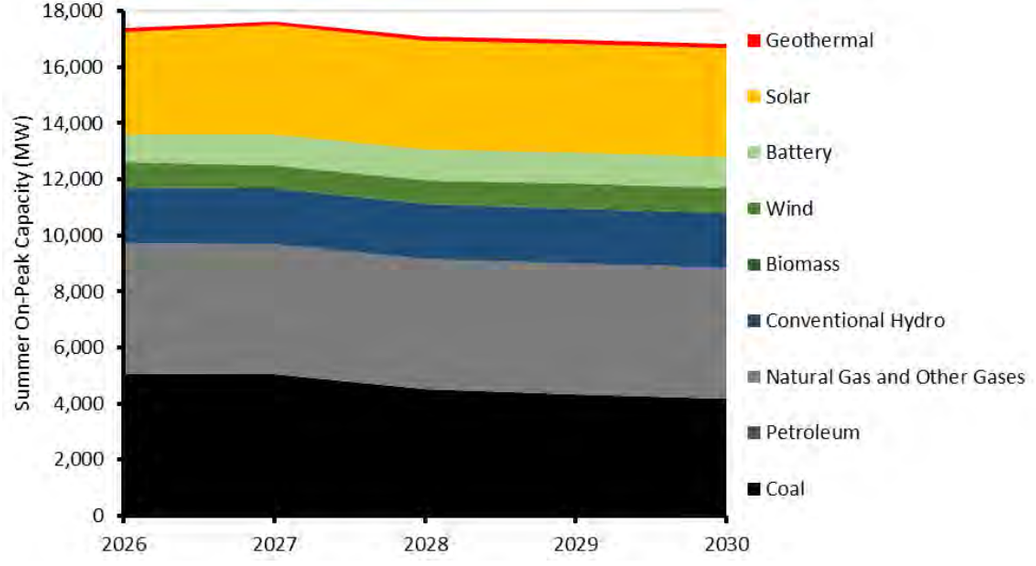
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is 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 LTRA 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 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,794	15,326	16,012	16,396	16,762	17,099	17,202	17,268	17,344	17,467
Demand Response	670	670	670	670	670	670	670	670	670	670
Net Internal Demand	14,124	14,656	15,342	15,726	16,092	16,429	16,532	16,598	16,674	16,797
Additions: Tier 1	2,125	2,453	2,453	2,466	2,466	2,466	2,466	2,453	2,466	2,466
Additions: Tier 2	973	1,018	1,270	1,279	1,279	1,279	1,279	1,270	1,279	1,279
Additions: Tier 3	127	1,162	2,024	2,616	4,209	4,726	5,665	6,203	6,332	6,332
Net Capacity Transfers (WECC Model)	1,822	2,545	2,420	1,820	1,698	1,400	1,400	1,400	1,400	1,400
Existing-Certain and Net Transfers	17,125	17,763	17,097	16,357	16,071	15,736	15,729	15,315	15,288	15,280
Anticipated Reserve Margin (%)	36.3%	37.9%	27.4%	19.7%	15.2%	10.8%	10.1%	7.1%	6.5%	5.7%
Prospective Reserve Margin (%)	43.2%	44.9%	35.7%	27.8%	23.1%	18.6%	17.8%	14.7%	14.2%	13.3%
Reference Margin Level (%)	13.5%	14.0%	13.6%	12.4%	12.3%	12.1%	12.1%	12.5%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Basin Highlights

- The ARM does not fall below the RML during the 2025–2035 time frame. IPCO and PACE participate in the Western Resource Adequacy Program (WRAP).
- The Basin subregion shows three LOLH in 2027 totaling approximately 3 MWh of EUE in June and July at hours beginning 18:00 and 19:00. In 2029, the subregion shows 310 LOLH totaling approximately 200,892 MWh of unserved energy. Over 90% of the EUE occurs between the hours of 17:00–22:00 from June to September.
- For 2027 and 2029, the peak hour is projected to occur in July at hour beginning 15:00.
- The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

WECC-Basin Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	5,068	5,041	4,508	4,326	4,177
Petroleum	5	5	5	5	5
Natural Gas	4,655	4,634	4,634	4,655	4,655
Biomass	31	31	31	31	31
Solar	3,668	3,899	3,899	3,884	3,884
Wind	900	826	826	897	882
Geothermal	139	139	139	139	139
Conventional Hydro	1,962	1,976	1,968	1,954	1,954
Other	31	31	31	19	19
Battery	967	1,090	1,090	1,092	1,092
Total MW	**17,428**	**17,672**	**17,130**	**17,003**	**16,839**

WECC-Basin Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2026–2035 time frame. The Idaho Power and PacificCorp East balancing areas both participate in WRAP, the first regional reliability planning and compliance program in the West.

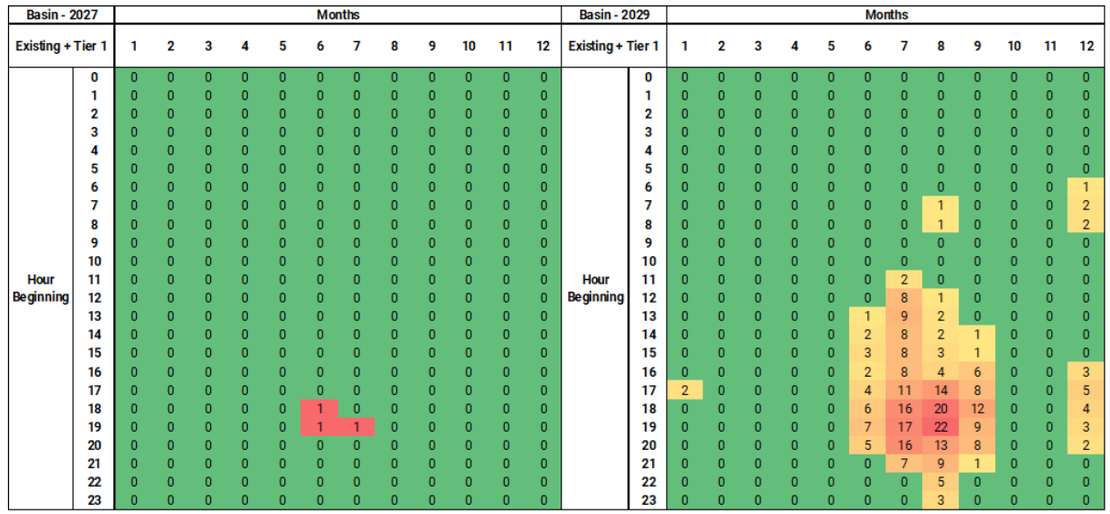
Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC's internally developed modeling tool that performs energy based ProbAs that support NERC's LTRA and seasonal assessments, as well as WECC's Western Assessment of Resource Adequacy (WARA).

Although the WECC-Basin assessment area's ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs after 2027, unserved energy and load-loss increase in the ProbA results. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

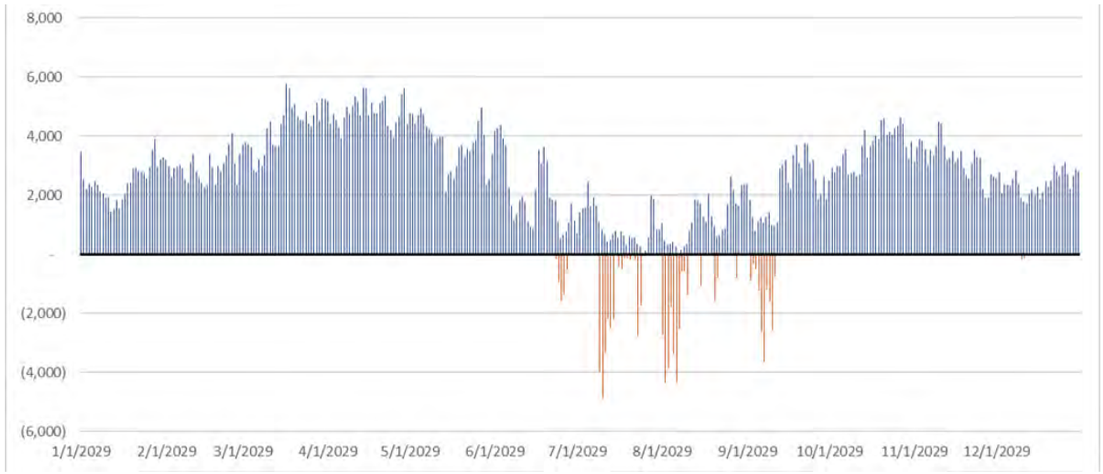
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
*** No prior results as the assessment area is new for the 2025 LTRA.**			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. In the ProbA results illustrated in the following heat map figure, risk is most concentrated to the month of peak demand (June) and the hours around sunset as solar output declines. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime.



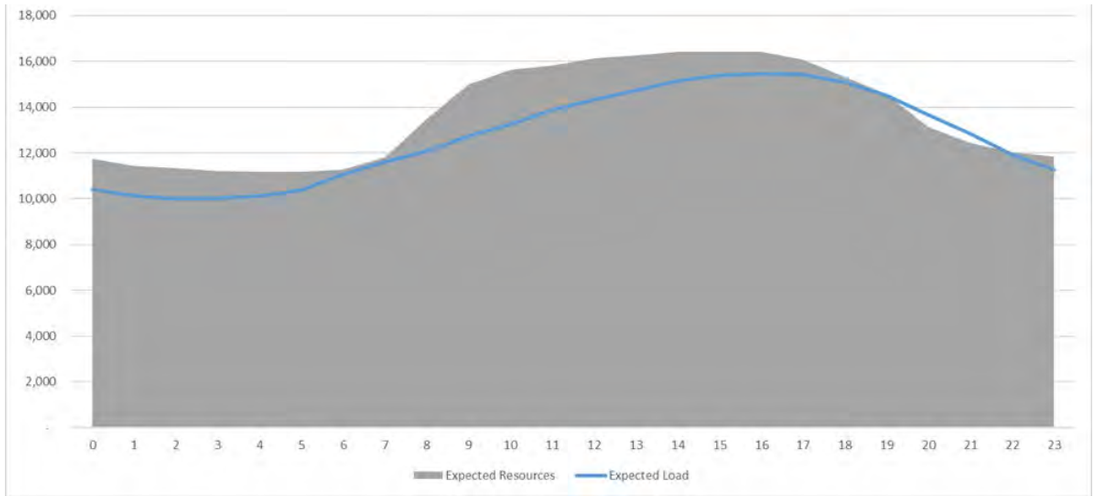
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Basin has excess energy that can be transferred to neighboring areas. During peak summer months, however, more of WECC-Basin's resources are needed for its own internal demand and, at times, energy deficits that must be met by importing energy from neighbors can exceed 4,000 MW.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. LOLH occurs at hour of 17:00 to 21:00 in 2029. This coincides with the evening solar down ramp and the persistence of elevated demand after the peak hour. The profile for the 2027 study year is similar but limited to the 18:00 to 19:00 hour. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Basin assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual growth rate for Basin is 2.5%. The primary drivers are data centers and semiconductor manufacturing. Large-load additions in the forecast are 1,223 MW through 2035.

Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows the utility to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year-to-year based on factors such as the availability of water and program parameters. PacifiCorp states in its most recent IRP that it plans to reach more than 1,100 MW of dispatchable DR by 2042, a 21% increase from its previous plan. The company's dispatchable DR programs include residential and small commercial air-conditioner load control programs, irrigation load management programs, and approximately 200 MW of evergreen interruptible contracts.

Distributed Energy Resources

BTM DER impacts are reflected in the demand forecasts (net of the DERs). BAs did not report a forecast for BTM resources.

Generation

Operational and planning issues related to generation in WECC-Basin include the following:

- **Aging Thermal Resource Fleet:** An aging thermal resource fleet is a year-round concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. Maintenance is planned years in advance and avoided during summer peak season as much as possible. Quarterly evaluations are done to adjust maintenance schedules as needed.
- **Gas Fleet Derates:** During the winter, gas resources may be derated during extreme cold and precipitation events for equipment issues such as snow-clogged inlet filters. This issue is remedied by monitoring filters and changing them out as needed.
- **Hydro Variability:** Hydro resources in this subregion are subject to seasonal and multi-year fluctuations in water supply. This is a year-round concern that requires persistent monitoring. Regular updates to near-term hydro forecasts ensure system operators can be ready for a range of potential hydro output.
- **Solar Variability:** As the solar capacity in this subregion grows, solar ramps are becoming a concern on summer evenings. Large declines in solar output require the dispatch of flexible resources to meet demand. In addition, during the winter solar generation tends to be significantly lower. BESS that typically charge from solar must charge from other resources. Wind and solar forecasts are used to estimate energy availability to serve load versus the amount available for BESS charging, and other resources are dispatched accordingly.
- **Wind Variability:** Particularly during the winter, the timing and volume of wind generation can vary significantly between forecasts and actuals. This is due to the unpredictable behavior of winter storms that may overspeed turbines, or cold temperatures mixed with moisture that may result in the icing of turbine blades.

Electric-Gas Coordination

Electric-gas coordination in long-term planning studies is considered for at least one Basin entity. For integrated resource planning assumptions, Resource Planners reach out to gas traders to confirm pipeline capability to serve existing and future generating asset needs. Gas supply constraints are not explicitly modeled but are inherently reflected in the GADs data used to develop long-term models.

Maintaining gas supplier diversity is one strategy implemented to reduce the risk of fuel shortages and delivery issues in this subregion. In addition, at least one entity in this subregion participates in the Northwest Mutual Assistance Agreement (NWMAA). This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving those resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

Idaho Power serves ~63% of the state's electricity load and is targeting 100% clean electricity by 2045; Idaho has no state Renewable Portfolio Standard (RPS) or other clean energy target. Utah has enacted a voluntary renewable portfolio goal of 20% renewable energy by 2025. As of 2023, 15.5% of electricity generated in the state was renewable, putting the state on a path to meet the goal.

Transmission

PacifiCorp's Energy Gateway Transmission Plan addresses future transmission requirements necessary to serve PacifiCorp's Network Load customer needs. In total, the Energy Gateway Transmission plan, initiated in May 2007, adds approximately 2,000 miles of new transmission lines. Segments A, B, C, F, G and parts of Segment D have been completed. Segment D.3 Bridger/Anticline to Populus has a planned in-service date of 2034; Segment E Populus to Hemingway is beyond the 10-year planning horizon.

The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned in-service date of 2027. This ~295-mile 500 kV transmission line provides ~1,000 MW of bidirectional capacity increase between the Northwest and Idaho.

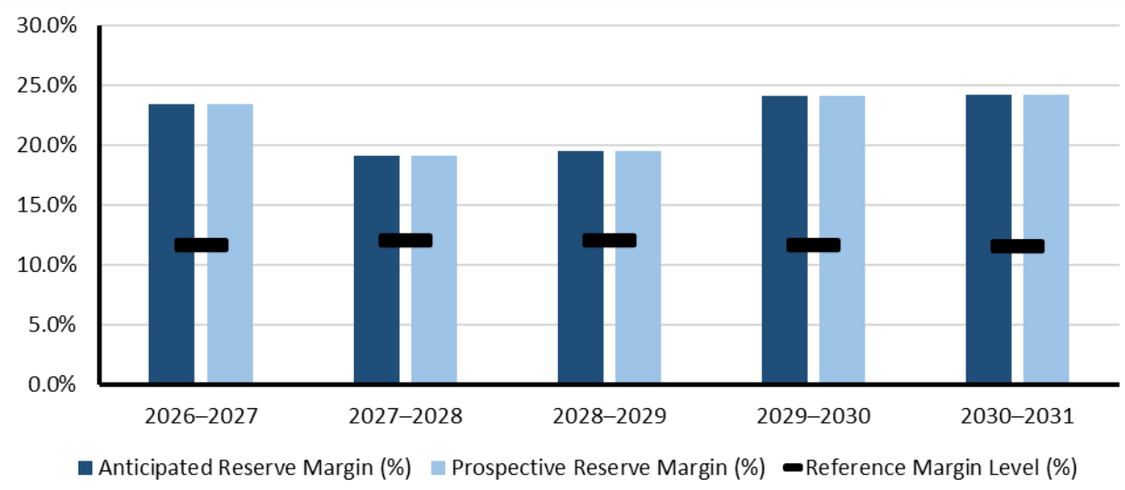


WECC-British Columbia

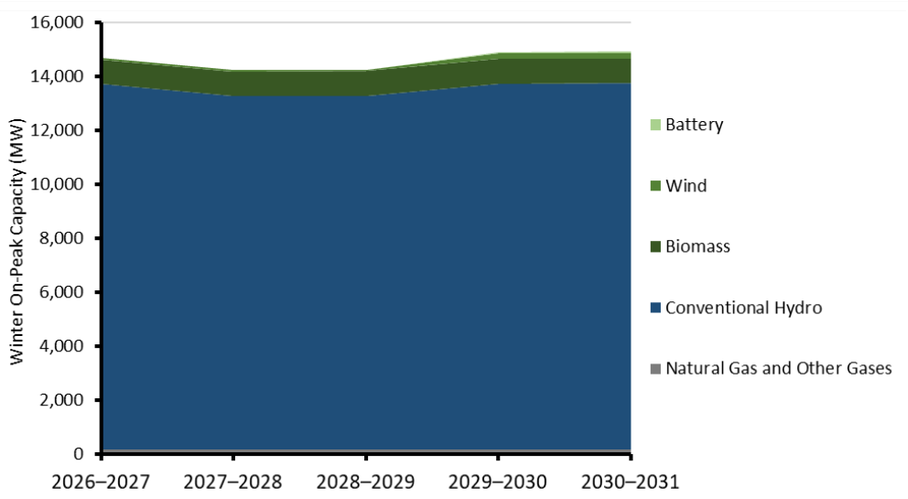
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia Bulk Electric System and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Additions: Tier 1	636	620	625	850	863	863	863	814	863	863
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	381	369	381	381
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	14,072	13,638	13,638	14,072	14,072	14,072	14,072	13,638	14,072	14,072
Anticipated Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Prospective Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Reference Margin Level (%)	11.7%	12.1%	12.1%	11.6%	11.6%	11.6%	11.5%	11.9%	11.5%	11.4%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-British Columbia Highlights

- WECC-British Columbia's anticipated reserve margin does not fall below the RML during the 2025–2035 timeframe.
- British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period.
- British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Hydro variability is the biggest operational issue related to generation in WECC-British Columbia.
- BC Hydro's most recent 10-year capital plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	170	170	170	170	170
Biomass	900	903	903	900	900
Wind	73	59	59	222	222
Conventional Hydro	13,544	13,104	13,109	13,560	13,573
Other	22	22	22	22	22
Battery	0	0	0	49	49
Total MW	14,708	14,258	14,263	14,922	14,935

WECC-British Columbia Assessment

Planning Reserve Margins

BC Hydro has used the one-day-in-10-years LOLE standard since 1975. Using a probabilistic model, BC Hydro concluded in its updated 2021 IRP that a 12% PRM of dependable generating capacity was required to ensure system resource adequacy. WECC-British Columbia's ARM does not fall below the RML during the 2025–2035 time frame.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Clean Electricity Regulations were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Provincial policies in BC that might affect resource planning and procurement include the Renewable Energy Projects Act (May 2025), (which streamlines permitting and grants the BC Energy Regulator broader approval powers for wind, solar, and transmission projects) and the BC Clean Power Action Plan (which aims to double clean electricity supply by 2050 and includes a new biennial procurement cycle for renewable resources).

BC Hydro is included in the Powerex footprint in WRAP. The WRAP defines an adequate reserve margin for its footprint for an 18-month forward period based on a loss of load expectation reliability threshold of one event day in 10 years. WRAP uses an ELCC methodology to determine capacity contribution in its analysis. The WRAP is a non-binding program for Winter 2025–26 but is currently planned to transition to a fully binding program with deficiency charges sometime in 2027. For 2025–2026 Winter, monthly PRMs for the Northwest WRAP subregion (called Mid-Columbia) range between 11.7% and 27.2%. For 2026 Summer, a PRM range between 14.2% and 22.3% is reported.

Energy Assessment, including non-peak hour risk

ProbA Results

British Columbia does not show any LOLH or EUE in 2027 or 2029.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

British Columbia did not have LOLH in 2027 or 2029; therefore, no additional reporting or visualizations are provided.

Demand

British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period. The primary driver for demand growth in British Columbia is natural gas processing. Significant, but uncertain, effects on demand are also expected because of commercial and residential electrification and simultaneous advances in EE in those two sectors.

Distributed Energy Resources

BC Hydro has a net metering program. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

With its abundant hydro, British Columbia is already approximately 95% carbon free. The CleanBC Roadmap states, "By 2030, BC will phase out BC Hydro's last gas-powered facility so the electricity we make is 100% clean."

British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Tier 3 additions include 500 MW of conventional hydro.

Hydro variability is the main operational and planning issue related to generation in WECC-British Columbia. Over 80% of British Columbia's capacity is comprised of hydro resources, making hydro variability a concern year-round. While parts of British Columbia remain in drought classification as of the end of October 2025, many of the province's basins have recovered and conditions are now better for this time of year than in the prior two years. Drought indices for 2026–2027 remain dependent on this year's snowpack accumulation and subsequent seasonal rain. At this time, it is too soon to forecast whether drought conditions will persist or continue easing into next season for the BC Hydro integrated system. Power imports from the United States to British Columbia assist in maintaining water storage levels. More than a fifth of the power in the province was imported from the United States in 2024. Increasing electrification trends coupled with potential continued drought conditions may exacerbate the need for imports to the region in the future.

As BC is working to phase out its last natural-gas-fired power generation units over the next five years, electric-gas coordination issues are not anticipated for power supply. However, BC's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to each other when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

Energy Storage

BC Hydro is expected to add 50 MW of Tier 1 battery energy storage over the next 10 years. Battery storage in the West is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the British Columbia transmission planning regions from all its neighbors is 2,897 MW in 2024 Summer and 3,078 MW in 2024/25 Winter. These values translate to approximately 31% of peak summer load and 27% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta).

Transmission

BC Hydro's most recent 10-Year Capital Plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets. These changes are expected to shorten development lead-times, boost renewable energy procurement, and enhance grid infrastructure planning.

Reliability Issues

Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in load caused by extreme weather, wildfires, atmospheric rivers, and heat waves or cold snaps, to add stress to the transmission network. Lastly, aging infrastructure could add to higher forced outage risk if supply chain disruptions create project delays, as has been occurring across the Western Interconnection in recent years.

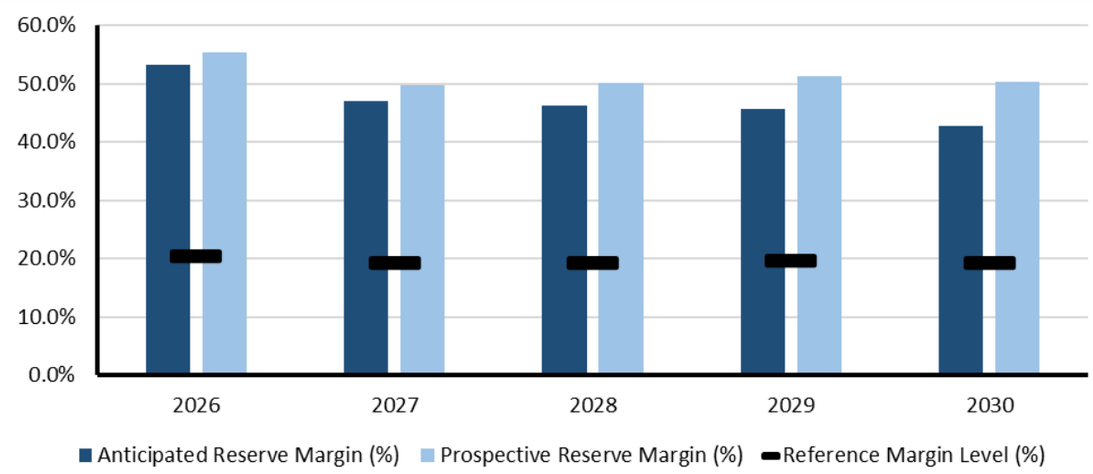


WECC-California

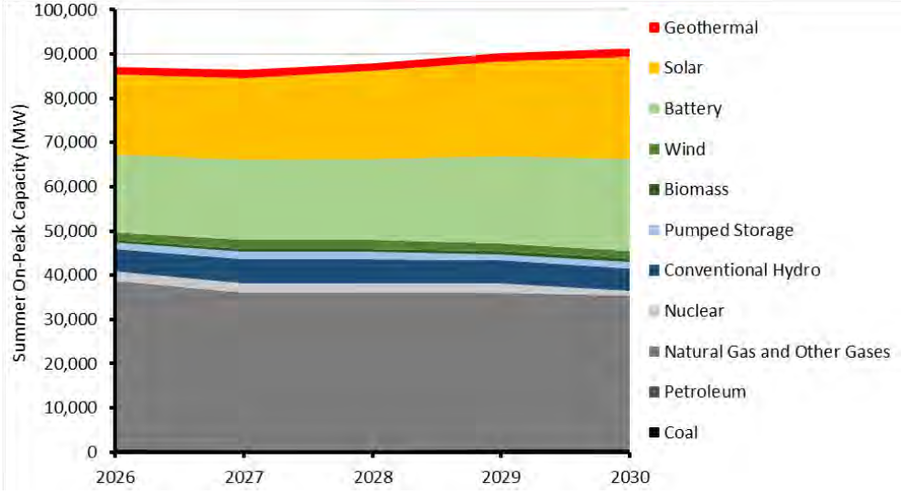
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock 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 LTRA 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 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	58,165	60,060	61,547	63,261	65,221	66,879	68,315	69,759	71,373	73,017
Demand Response	756	764	775	783	795	799	812	823	836	836
Net Internal Demand	57,409	59,296	60,772	62,478	64,426	66,079	67,504	68,936	70,537	72,182
Additions: Tier 1	11,558	13,202	14,765	17,206	19,945	19,945	21,532	22,541	23,771	25,622
Additions: Tier 2	1,288	1,552	2,388	3,489	4,974	4,974	6,509	8,475	9,208	9,244
Additions: Tier 3	10	10	10	10	557	557	557	562	557	557
Net Capacity Transfers (WECC Model)	561	583	651	639	541	234	310	314	298	287
Existing-Certain and Net Transfers	76,371	73,982	74,050	73,773	71,969	70,585	70,661	70,925	70,649	70,613
Anticipated Reserve Margin (%)	53.2%	47.0%	46.1%	45.6%	42.7%	37.0%	36.6%	35.6%	33.9%	33.3%
Prospective Reserve Margin (%)	55.4%	49.6%	50.1%	51.2%	50.4%	44.5%	46.2%	47.9%	46.9%	46.1%
Reference Margin Level (%)	20.3%	19.2%	19.3%	19.7%	19.3%	19.1%	18.9%	17.8%	18.3%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-California Highlights

- The ARM does not fall below the RML. Further, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The California Public Utilities Commission (CPUC) recently increased the PRM requirement for 2026 and 2027 from 17% to 18%. CPUC's ruling also maintains procurement targets that provide additional summer reliability resources by ordering IOUs to procure resources of 1,260 to 2,300 MW for the months of June through October in 2026 and 2027.

WECC-California Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	466	466	466	466	466
Coal*	16	16	16	16	16
Petroleum	103	103	103	103	103
Natural Gas	38,144	35,507	35,507	35,468	34,837
Natural Gas*	38,144	34,994	34,994	35,468	34,837
Biomass	734	745	749	749	749
Solar	18,126	18,574	19,936	21,506	23,065
Wind	1,643	1,991	2,000	1,650	1,650
Geothermal	1,809	1,808	1,808	1,809	1,809
Conventional Hydro	5,112	5,426	5,426	5,112	5,112
Pumped Storage	1,401	1,549	1,549	1,401	1,401
Nuclear	2,152	2,151	2,151	2,152	1,076
Other	194	194	194	194	194
Battery	17,486	18,088	18,275	19,731	20,911
Total MW	87,368	86,601	88,164	90,340	91,372
Total MW*	86,918	85,637	87,200	89,890	90,922

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-California Assessment

Planning Reserve Margins
The ARM does not fall below the RML. The California Public Utilities Commission (PUC) recently released a PRM increase for 2026 and 2027 from 17% to 18%. The ruling also increases the PRM procurement target from 1,260 to 2,300 MW for the months of June through October for 2026 and 2027 (divided across the IOUs). Note, the CPUC's reserve margins are not used in WECC's methodology for the LTRA.

Energy Assessment, including non-peak hour risk
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results
The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

For 2027 and 2029, the peak hour is projected to occur in early September at hour beginning 16:00. California does not show any LOLH or EUE in either 2027 or 2029. No risk period visualizations are included for this subregion as there were no identified risk hours.

Demand
Average annual demand growth rate for WECC-CA is 2.4%. The primary drivers are transportation electrification and incremental load for extreme heat events. Large-load additions in the forecast are 4,993 MW through 2035.

Demand-Side Management
DR accounted for about 2.6% (1,400 MW) of total system resource adequacy capacity in the summer of 2024 compared to about 3 to 4% in the previous four summers. This drop is mainly due to a change in CPUC rules removing the PRM and transmission adders totaling over 11% previously applied to DR capacity.

DR was supplied by CPUC-regulated utility programs, non-utility third-party programs, and non-CPUC jurisdictional load-serving entities (municipal utilities, etc.). Utility DR accounts for about 76% of DR used to meet resource adequacy requirements. About 85% of this capacity was bid into the real-time market during the most critical hours of summer 2024. When dispatched, this category reported curtailing about 81% of scheduled load reductions.

Non-utility (third party) DR accounts for about 18% of DR used as resource adequacy capacity requirements, with actual load reductions of about 54% of scheduled. However, during some hours, this sector exceeded the scheduled level.

Non-CPUC jurisdictional load serving entities (municipal utilities, etc.) utilize an average of about 75 MW of DR—or about 6% of DR used to meet total ISO system resource adequacy requirements. Since this capacity is not bid or scheduled into the ISO market, its performance cannot be verified.

Distributed Energy Resources
A recent policy change in California significantly increased the payback period for residential BTM PV. As predicted, installations of residential rooftop solar systems have fallen to near three-year lows over the past year; existing systems were grandfathered in. Now, the California legislature is considering a bill to undo that grandfathering by reducing those existing net metering contracts with IOUs from 20 years to 10. AB 942 would impact the value of solar on the nearly 2 million homes that have installed panels years ago by shifting them to the "net billing tariff" that pays approximately 75% lower rates for energy sent back to the grid. Given California's shifting policy environment, it is difficult to predict future adoption of BTM PV solar.

Generation

- **Aging Thermal Resource Fleet:** During the summer, aging thermal resources can become a concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. In addition, thermal plant and system operators are becoming increasingly hard to replace, as there appears to be difficulty in finding personnel with the necessary experience to fill these rolls. Succession planning is becoming an integral part of successful thermal plant operation.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round. BTM resource generation can be masked from the transmission operator and BA. For example, localized cloud coverage limiting BTM output has been seen to increase demand by 200 MW, requiring unplanned additional resources to be dispatched.

Flexible operating reserves remain on standby to address the uncertainty associated with BTM output.

- **BESS Fires:** BESS fires have occurred in California. These are isolated events that can render a BESS inoperable. Electrical faults, manufacturing defects, degradation due to aging, and gas buildup can all lead to fires. New technologies for passive fire suppression, such as immersion cooling, are being developed to reduce the occurrence of BESS fires.
- **Gas Fleet Derates:** Gas resources in this subregion can be derated during extremely hot weather in the summer due to ambient conditions. Quantifying gas fleet limitations and ensuring there are alternative resources available to meet demand is paramount.
- **Hydro Variability:** Primarily during the summer season, variations in annual precipitation can have a significant impact on water supply. Extended droughts can reduce head pressure, directly resulting in the reduction of hydro capacity. Improvements in hydro models for run off and precipitation are in progress to address these concerns. For resource adequacy models, a 1-in-5 dry-year planning scenario is used.
- **Inertia Decline on System:** Local and federal regulations have driven a reduction in traditional spinning mass generators, which has exacerbated frequency deviations in California. Operating plans are being updated with the necessary steps to mitigate this issue. This issue is observed year round.
- **Solar Variability:** Solar output variability is a concern year round. Spring, fall, and winter often have overcast cloud coverage in California, which can make solar output difficult to forecast. Summer evenings tend to be a time of day when demand is elevated but solar output declines. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.
- **Wind Variability:** Wind variability is an operational concern year round. Toward the end of summer, the beginning of winter, and the beginning of spring, Santa Ana Winds can create overspeed conditions for wind turbines, limiting their output. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.

Electric-Gas Coordination

Most entities in California consider electric-gas coordination in long-term planning studies. Resource Planners collaborate with gas supply teams to gather assumptions on forecasted gas deliveries and pricing. Constraints are not directly incorporated in resource planning studies.

Operating Procedure 4120 ensures that CAISO provides daily estimated gas usage reports to gas transmission operators (GTO). These are used as the basis for gas curtailment event planning. This procedure helps mitigate risks associated with gas supply limitations that may impact generation resources and applies to both real-time and day-ahead operations. In addition, participants of RC West have formed the Real-Time Working Group (RTWG). This group convenes prior to extreme weather events to prepare for potential gas supply interruptions. California entities that are part of RC West also participate in the Northwest Mutual Assistance Agreement (NWMMA). Communication protocols include following NERC Reliability Standard COM-002-4 which contains predefined communication procedures. In addition, plant operators work directly with power supply and gas schedulers to coordinate scheduling and dispatch of gas generating resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

California has a mandate for its electricity supply to be 60% carbon free by 2030 and is currently on track to meet that level. The requirement for 100% carbon free is set at 2045.

Transmission

The ITCS report showed that in a heat wave Northern California may be energy-deficient.

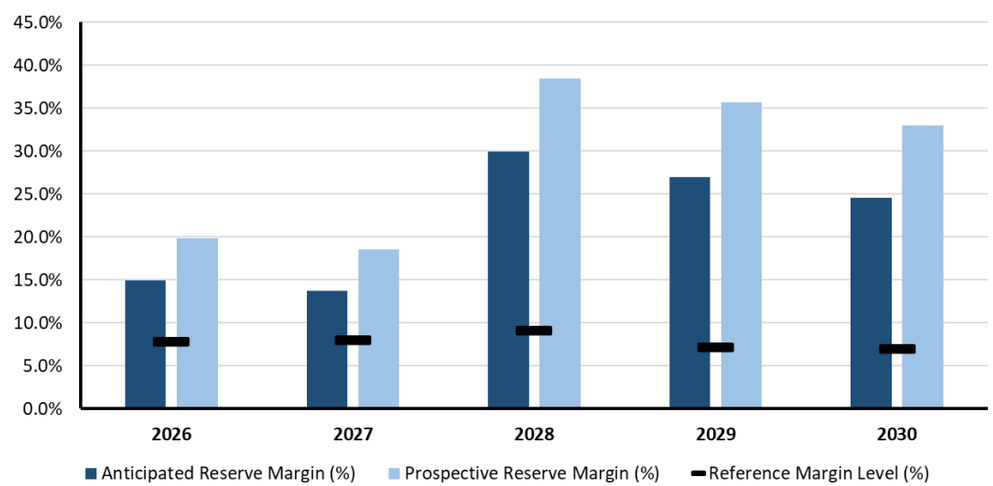


WECC-Mexico

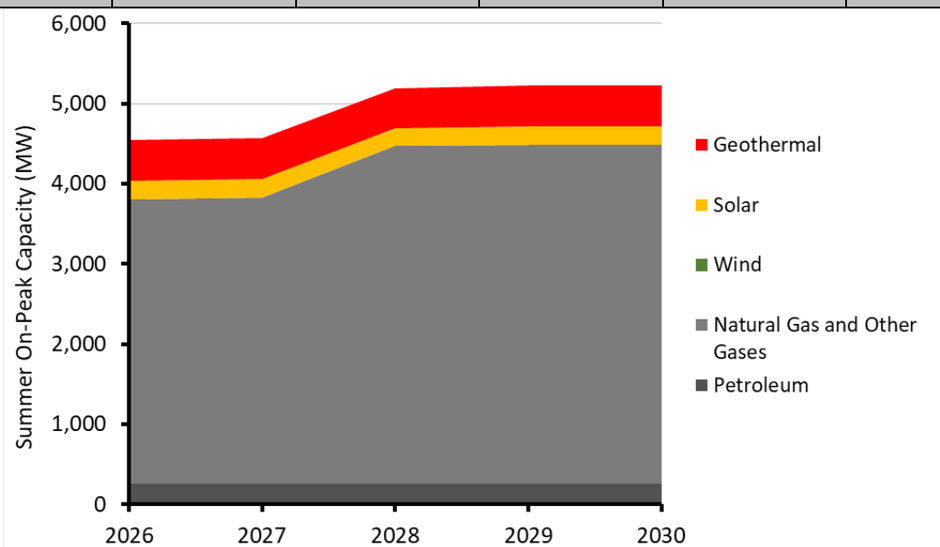
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting 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 LTRA 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 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Additions: Tier 1	717	722	1,396	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Additions: Tier 2	196	198	367	392	392	392	392	367	392	392
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Capacity Transfers (WECC Model)	0	131	410	482	600	600	600	600	600	600
Existing-Certain and Net Transfers	3,825	3,982	4,209	4,307	4,425	4,425	4,425	4,409	4,425	4,425
Anticipated Reserve Margin (%)	14.9%	13.8%	29.9%	27.0%	24.6%	20.0%	15.7%	11.4%	8.0%	4.5%
Prospective Reserve Margin (%)	19.9%	18.6%	38.4%	35.7%	33.0%	28.1%	23.5%	18.4%	15.2%	11.5%
Reference Margin Level (%)	7.8%	8.0%	9.1%	7.2%	7.0%	6.8%	6.7%	7.4%	6.4%	6.3%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Mexico Highlights

- Centro Nacional de Control de Energía (CENACE) is adding three natural-gas-fired combustion turbine generators (totaling 780 MW in summer capacity) by Summer 2026, increasing planned reserves to above RMLs. An additional 740 MW of natural-gas-fired capacity is in development between 2026 and 2027.

WECC-Mexico Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	0	0	0	0	0
Petroleum	259	261	258	259	259
Natural Gas	3,540	3,566	4,212	4,224	4,224
Biomass	0	0	0	0	0
Solar	229	231	214	229	229
Wind	7	5	6	7	7
Geothermal	506	510	505	506	506
Conventional Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	0	0	0	0	0
Battery	0	0	0	0	0
Total MW	4,542	4,573	5,195	5,225	5,225

WECC-Mexico Assessment

Planning Reserve Margins
The ARM is above the RML until 2035, the last year of the assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the *2025 LTRA*.			

Demand
Average annual demand growth rate for WECC-Mexico is 4.3%. Large-load additions in the forecast are 161 MW through 2035.

Generation
Operational and planning issues related to generation in WECC-Mexico include the following:

- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand is highest.
- Electric-Gas Coordination: Electric-gas coordination is considered in long-term planning studies for the WECC-Mexico area. Current and future gas projects and constraints that could compromise supply to generators are incorporated in planning studies. Constant gas supply monitoring is conducted to ensure generating assets remain reliable throughout the year. Multiple suppliers are also available to generators in WECC-Mexico. This allows for supply redundancy if one supplier is experiencing limitations. Communication between gas suppliers and system operators includes the sharing of gas infrastructure maintenance information and consumption forecasts which are provided on a weekly, monthly, and annual cadence.

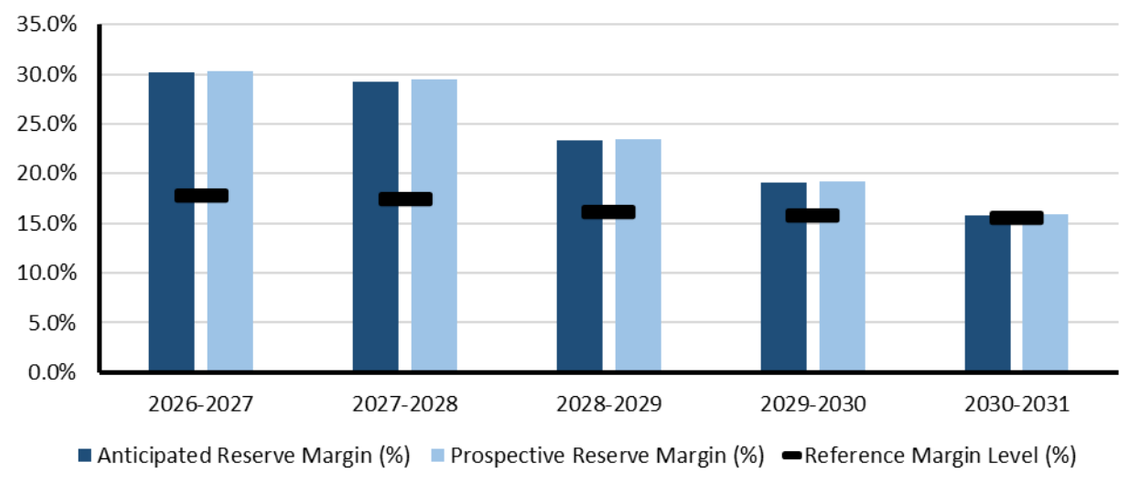


WECC-Northwest

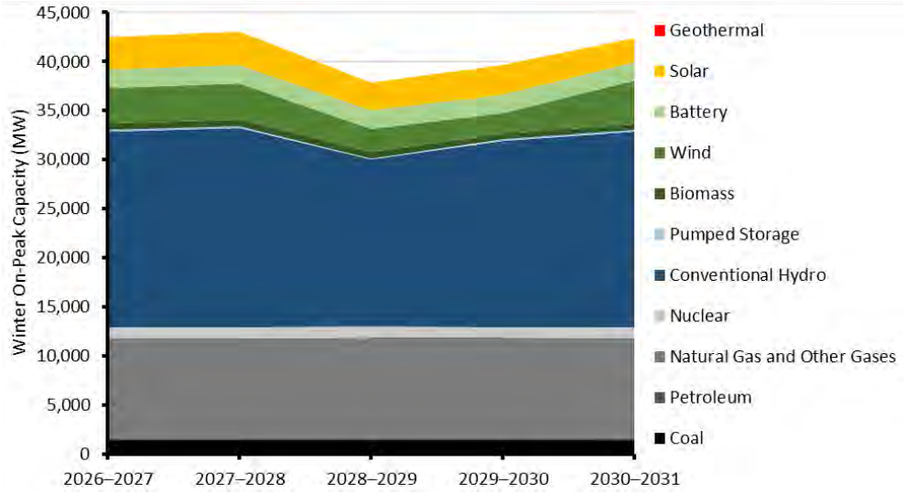
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for 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 LTRA 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 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	34,426	34,930	36,038	37,017	37,939	38,821	39,455	40,083	40,563	41,064
Demand Response	30	30	30	30	30	30	30	30	30	30
Net Internal Demand	34,396	34,900	36,008	36,987	37,909	38,791	39,425	40,053	40,533	41,034
Additions: Tier 1	3,463	3,463	3,219	3,219	3,219	3,219	3,463	3,232	3,221	3,217
Additions: Tier 2	10	49	56	56	56	56	49	56	56	56
Additions: Tier 3	697	830	939	4,958	5,389	5,605	6,267	5,963	5,921	5,903
Net Capacity Transfers (WECC Model)	7,242	7,630	7,316	7,066	6,896	6,825	6,825	6,825	6,630	5,841
Existing-Certain and Net Transfers	41,332	41,653	41,169	40,828	40,652	40,564	40,724	40,558	40,360	39,573
Anticipated Reserve Margin (%)	30.2%	29.3%	23.3%	19.1%	15.7%	12.9%	12.1%	9.3%	7.5%	4.3%
Prospective Reserve Margin (%)	30.3%	29.4%	23.4%	19.2%	15.9%	13.0%	12.2%	9.5%	7.7%	4.4%
Reference Margin Level (%)	17.8%	17.4%	16.1%	15.8%	15.5%	15.3%	15.9%	15.0%	14.9%	14.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Northwest Highlights

- The ARM falls below the RML starting in Winter 2031–2032. The assessment area would need additional resources to meet resource adequacy criteria. More details on members participating in the WRAP can be found on the WRAP Area Map.
- For 2027 and 2029, the peak hour is projected to occur in January at hour beginning 10:00.
- Resource adequacy risk is not significant in the Northwest for 2027.
- In 2029, the Northwest subregion shows 8,080 MWh of EUE, with approximately 85% of that occurring between hours beginning 14:00–19:00 in August. Though the magnitude of EUE is greatest in the summer months, LOLH occurs at a greater frequency in the winter months, particularly in January.
- The majority of EUE occurs during the summer from hours beginning 17:00–19:00, during which period demand is elevated but solar output is dissipating.

WECC-Northwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,516	1,516	1,475	1,475	1,475
Petroleum	97	97	95	95	95
Natural Gas	10,539	10,533	10,480	10,480	10,480
Biomass	657	617	615	536	536
Solar	1,545	1,544	1,622	1,622	1,622
Wind	2,149	2,149	1,319	1,311	1,311
Geothermal	4	4	4	4	4
Conventional Hydro	17,855	17,835	18,279	18,275	18,270
Pumped Storage	146	146	149	149	149
Nuclear	1,112	1,112	1,108	1,108	1,108
Battery	1,934	1,934	1,927	1,927	1,927
Total MW	37,553	37,486	37,072	36,981	36,976

WECC-Northwest Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Winter 2031–2032. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.

Non-Peak Hour Risk and Energy Assurance

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs over the assessment period, unserved energy and load-loss hours increase in the ProbA results.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0	36.64
LOLH (hours per Year)	N/A	0	85.00
* No prior results as the assessment area is new for the 2025 LTRA.			

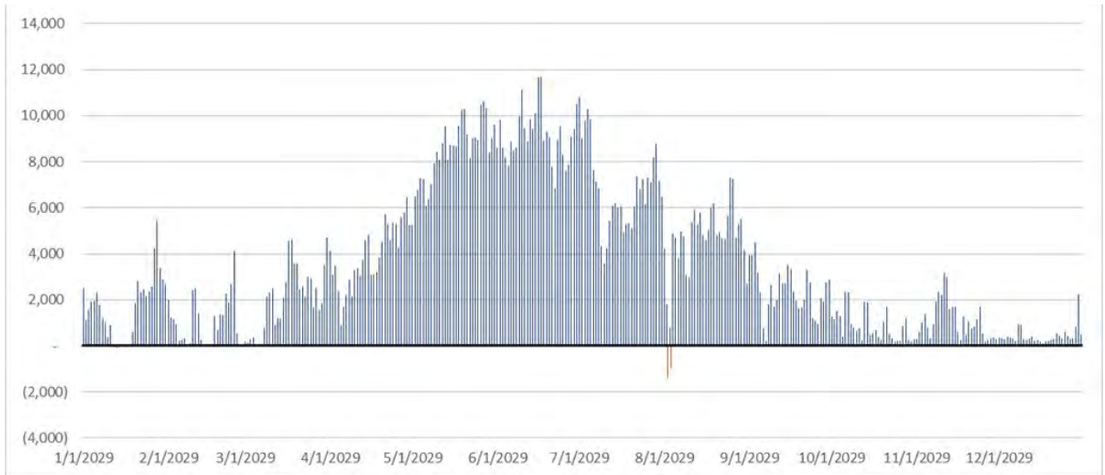
Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year.

Northwest - 2027	Months											
Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12
Hour Beginning 0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

Northwest - 2029	Months											
Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12
Hour Beginning 0	2	0	0	0	0	0	0	0	0	0	0	0
1	2	0	0	0	0	0	0	0	0	0	0	0
2	4	0	0	0	0	0	0	0	0	0	0	0
3	4	0	0	0	0	0	0	0	0	0	0	0
4	4	0	0	0	0	0	0	0	0	0	0	0
5	2	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	1
7	2	0	0	0	0	0	0	0	0	0	0	4
8	3	0	0	0	0	0	0	0	0	0	0	2
9	3	0	0	0	0	0	0	0	0	0	0	0
10	3	0	0	0	0	0	0	0	0	0	0	0
11	4	0	0	0	0	0	0	0	0	0	0	0
12	4	0	0	0	0	0	0	0	0	0	0	0
13	3	0	0	0	0	0	0	1	0	0	0	0
14	2	0	0	0	0	0	0	2	0	0	0	0
15	1	0	0	0	0	0	0	2	0	0	0	0
16	4	0	0	0	0	0	1	2	0	0	0	0
17	5	0	0	0	0	0	1	2	0	0	0	2
18	4	0	0	0	0	0	0	3	0	0	0	2
19	4	0	0	0	0	0	0	2	0	0	0	1
20	2	0	0	0	0	0	0	1	0	0	0	1
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

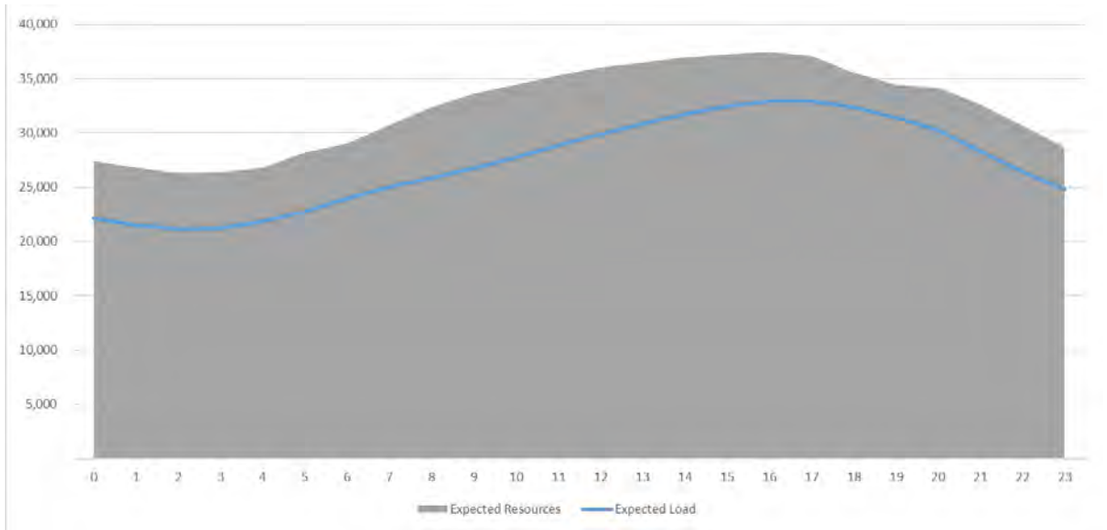
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Northwest meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Northwest has excess energy that can be transferred to neighboring areas. Winter months are when WECC-Northwest's excess energy is at its lowest, and at times in the 2029 study year internal resources are not sufficient for demand. In summer months, WECC-Northwest is projected to have its highest amount of excess energy, though these supplies can still be insufficient for modeled demand during extreme heat events. Such occurrences can cause deficits represented in the figure below, and energy can go unserved when neighboring areas do not have surplus energy to transfer.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. For the Northwest, this occurs in mid-to-late summer. LOLH occurs from hours beginning 14:00 through 19:00. The majority of EUE during these hours occurs from hours beginning 17:00–19:00, during which period demand remains elevated whereas solar output dissipates. There is no LOLH in 2027. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Northwest assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual demand growth rate for WECC-Northwest is 2.7%. The primary drivers are data centers, residential electrification, residential customer growth, transportation electrification, and semiconductor manufacturing. Large-load additions in the forecast are 7,652 MW through 2035.

Distributed Energy Resources

In the Northwest, Oregon IOUs continue to offer net metering with carryover credits within a calendar year and annual excess credits going to low-income programs. However, the state's largest IOU has proposed a change that largely mirrors California's revised lower credits; if adopted, this would slow the rate of installations in Oregon as well (where the latitude and climate already lengthen the customer's payback period relative to California).

In Washington, utilities have the option to propose a BTM PV credit that is less than the retail rate once they reach a threshold of 4% of their 1996 peak load. The current program is in effect until at least 2029. However, given the progress toward the 4% penetration rate (below), that year may trigger a slowdown in new installations of BTM PV.

Generation

Operational and planning issues related to generation in WECC-Northwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Older resources require additional maintenance and can be prone to forced outages or partial derates. Necessary maintenance and capital expenditures are made to ensure these generators provide reasonable performance when called upon. Planned maintenance outages for these resources may be done at a higher frequency during the shoulder months to avoid unplanned outages during the summer months. However, major upgrades to aging infrastructure reduce system capability for extended periods of time, increasing reliance on imports. Supply chain delays and staffing issues can cause planned outages to extend well beyond their anticipated end date. Staffing shortages have been noted by multiple entities in the Northwest.
- **Hydro Variability:** The Northwest has a large share of hydro resources in its portfolio making hydro generating capability a concern year-round. Seasonal hydro variability and below average inflows observed by some entities in this region from April through November of last year resulted in projects being ran at minimum flow. Underperforming hydro resources can result in entities relying heavily on imports to meet peak load hours. During extreme cold conditions, run of river hydro sites can also be derated due to icing. Performing maintenance during shoulder seasons can help keep hydro on-line during the winter and summer seasons. Improving hydro forecasting for short- and long-term planning models can assist system dispatchers with daily operating plans and resource planners in completing accurate resource adequacy studies.
- **Solar Variability:** Solar output variability due to cloud coverage can be a minor concern year-round in this subregion. Entities in this subregion state there are sufficient flexible resources in their portfolio to address solar output uncertainty.
- **Wind Variability:** Wind variability is of particular concern for this subregion during the winter. Cold weather mixed with moisture can cause icing conditions on wind turbine blades, which can severely derate a wind site. Entities in this subregion state that there are sufficient flexible resources in their portfolio to address wind output uncertainty in the winter.
- **Electric-Gas Coordination:** The Northwest subregion contains entities that consider electric-gas coordination in long-term planning studies, as well as entities that do not. Several gas supply options for future generating assets are evaluated to ensure alternatives exist if one supply point is curtailed. Price certainty from suppliers is also a major consideration in planning studies. Annual natural-gas-load studies are conducted to help identify parts of the gas distribution system that may experience low pressure during peak cold conditions. These areas of the gas system are identified, and recommendations to address this issue are prioritized and completed. If an issue cannot be addressed within a short period of time, contingency plans are developed for these areas during high gas demand or peak cold conditions. Entities in the Northwest subregion are participants in the NWMMA mentioned earlier in the Basin subregion. Status reports and planned resource output forecasts are communicated between electric and gas teams daily to ensure operational needs are met.
- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Washington is required to have zero coal generation by 2025, be greenhouse gas neutral by 2030 (can use offsets), and be 100% non-emitting by 2045 without using offsets. Oregon passed a requirement for its investor-owned utilities to be 80% below their 2005 emissions baseline by 2030, 90% below by 2035, and 100% below (zero emissions) by 2040. Montana has a 15% renewables target that has been met, with no incremental increases in the out-years.

Transmission: PacifiCorp's Blueprint transmission project will connect major resource and load areas in central and eastern Oregon through construction of approximately 320 miles of new 500 kV transmission line and associated 500 kV and 230 kV system upgrades, in three primary segments planned to be fully in-service in 2028 and 2032. The Blueprint project will largely parallel the existing Northwest AC Intertie 500 kV system, interconnecting at various points and requiring significant coordination with ac Intertie owners and other affected systems. Affected paths include WECC Paths 14, 66 and 75.

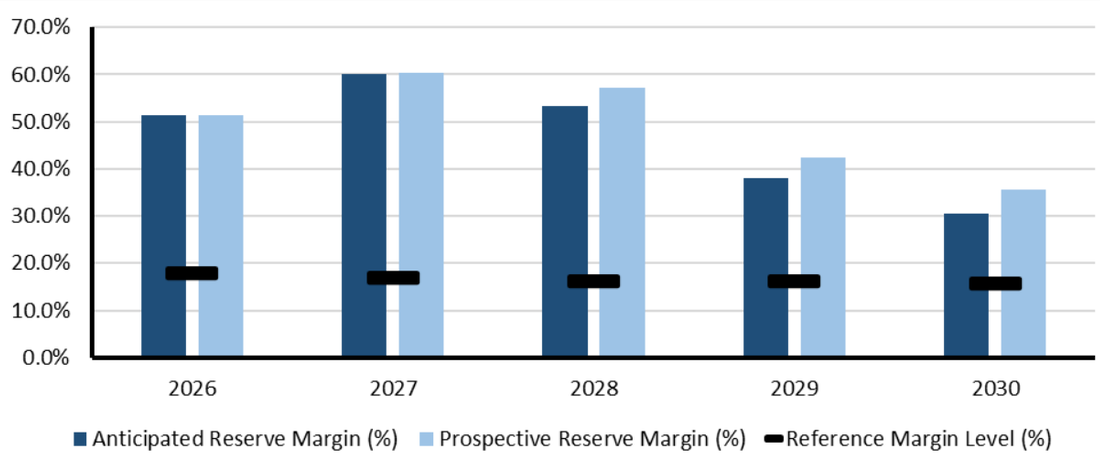


WECC-Rocky Mountain

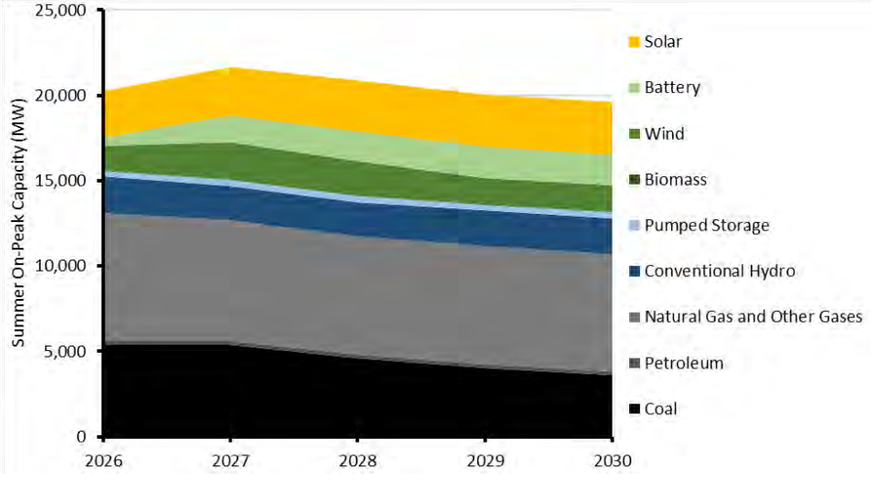
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and 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 LTRA 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 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,004	14,338	14,565	15,021	15,442	15,873	16,306	16,764	17,207	17,297
Demand Response	287	290	293	285	287	290	293	296	298	301
Net Internal Demand	13,717	14,048	14,272	14,736	15,154	15,583	16,013	16,468	16,909	16,997
Additions: Tier 1	1,771	3,486	3,979	4,079	4,079	4,079	4,355	4,299	4,079	4,079
Additions: Tier 2	0	45	585	640	761	761	810	810	761	761
Additions: Tier 3	17	178	925	1,160	1,373	3,207	3,276	4,188	4,274	4,370
Net Capacity Transfers (WECC Model)	391	661	852	179	50	23	0	0	0	0
Existing-Certain and Net Transfers	18,979	18,995	17,884	16,278	15,696	14,882	14,721	14,329	14,143	14,098
Anticipated Reserve Margin (%)	51.3%	60.0%	53.2%	38.1%	30.5%	21.7%	19.1%	13.1%	7.8%	6.9%
Prospective Reserve Margin (%)	51.3%	60.3%	57.3%	42.5%	35.5%	26.6%	24.2%	18.0%	12.3%	11.4%
Reference Margin Level (%)	17.8%	17.0%	16.2%	16.1%	15.7%	15.2%	13.5%	11.9%	14.1%	13.9%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Rocky Mountain Highlights

- ARM remains above the RML through 2033. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period.

WECC-Rocky Mountain Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	5,383	5,376	4,623	4,034	3,585
Coal*	5,053	5,376	4,429	3,379	2,180
Petroleum	204	204	204	204	204
Natural Gas	7,522	7,083	6,897	6,902	6,902
Biomass	6	6	6	3	3
Solar	2,695	2,873	3,002	3,071	3,071
Wind	1,437	2,218	2,054	1,555	1,550
Conventional Hydro	2,139	2,043	2,029	2,116	2,116
Pumped Storage	346	340	340	346	346
Other	126	126	126	126	126
Battery	496	1,547	1,726	1,817	1,817
Unknown	6	5	5	6	6
Total MW	20,359	21,820	21,011	20,178	19,725
Total MW*	20,029	21,820	20,817	19,523	18,320

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-Rocky Mountain

Planning Reserve Margins
The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. In Winter 2033–34, the ARM falls below the RML, but the prospective resources are expected to sufficiently cover a shortfall. No BAs in this region are WRAP participants.

The Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, has used a 16.3% long-term PRM requirement in its Electric Resource Plan (2021), based on a loss of load probability of 1-day every 10 years. PSCo's reserve margin is not used in WECC's methodology for the LTRA.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
*No prior results as the assessment area is new for the 2025 LTRA.			

Since WECC-Rocky Mountain does not show any LOLH or EUE in 2027 or 2029, no additional reporting of results or visualizations are provided.

Demand
Average annual demand growth rate for WECC-Rocky Mountain is 2.5%. The primary drivers are data centers, commercial customer growth, and industrial customer growth. Large-load additions in the forecast are 574 MW through 2035.

Demand-Side Management
PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its Demand Side Management & Beneficial Electrification Plan.

Distributed Energy Resources
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DERs).

Generation
Operational and planning issues related to generation in WECC-Rocky Mountain include the following:

- **Unplanned Outage Extensions:** Supply chain issues, unplanned discovery work, and vendor availability have driven unplanned extensions of resource outages in the Rocky Mountain area. Difficulty in boiler feed pump procurement has resulted in at least one generating asset being unavailable for over nine months. Another thermal site was undergoing a rotor swap and piping inspection, which revealed significant weld defects and pipe cracks. This resulted in a two-month outage being extended into the following year. A hydro site has been unavailable for much of 2024 due to a penstock leak which has been unable to be repaired due to vendor unavailability. Alternative vendors are being sought after for hydro repair work, and contracts to expedite the procurement of equipment will be in place going forward to mitigate these issues.
- **Solar and Wind Variability:** Smaller entities in the Rocky Mountain area have stated that wind and solar variability is a concern year-round due to a lack of geographic diversity. These entities are pursuing advancement into RTOs to leverage the advantages of a wider footprint and additional resources.
- **Electric-Gas Coordination:** The Rocky Mountain area contains entities that consider electric-gas coordination in long-term planning studies as well as entities that do not. For entities that do consider electric-gas coordination, peak capacity requirements for the local distribution company (LDC) and generating assets are inputs into long term planning models. Peak capacity requirements define the pipeline capacity and contractual volumes needed to fulfill LDC and electric needs. In addition, known and historical constraints on pipelines are considered in resource planning studies. Gas suppliers in this subregion have multiple delivery points to resources. This allows for an alternative location for delivery if one delivery point is inaccessible. In addition, gas supply teams provide an email with natural gas price information and constraints to generation dispatchers and marketers daily. During times of cold weather, this communication stream can be expanded to include interstate gas control and commercial operations.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Colorado requires investor-owned utilities to adopt plans to reduce greenhouse gas emissions by at least 80% by 2030, using a 2005 baseline. While the state is on track to achieve this, the additional goal of being 100% carbon free by 2040 is being discussed by utilities, regulators, and legislators, with a proposal to extend the out-year to 2050 in light of the upward pressure on the cost of renewables caused by potential repeal of tax credits and higher tariffs on imports.

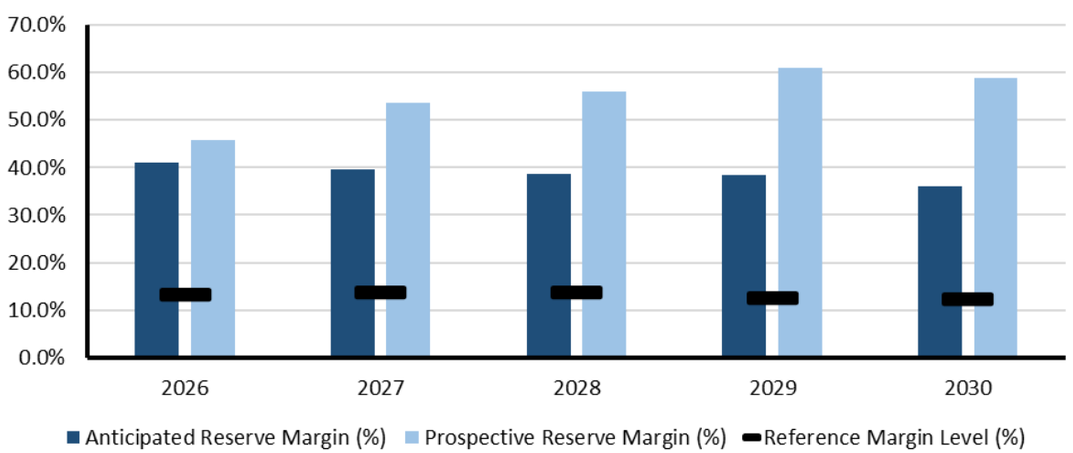


WECC-Southwest

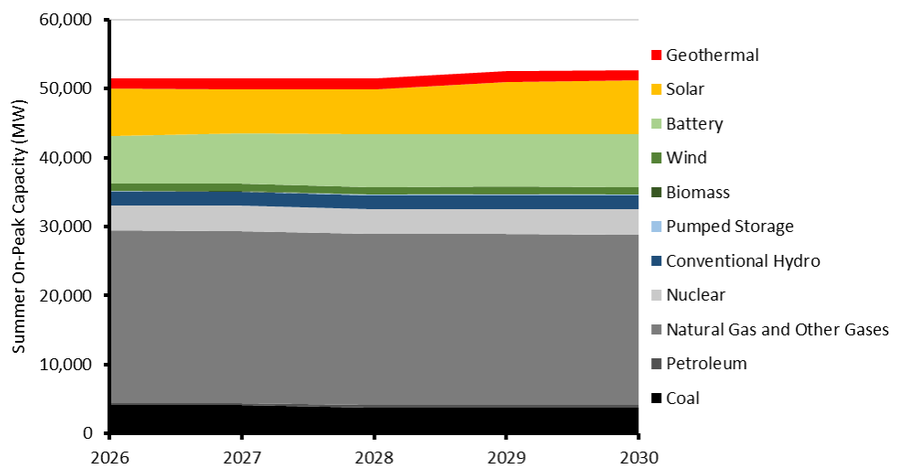
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for 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 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	37,407	38,911	40,429	41,887	43,551	44,772	45,664	46,317	47,226	47,988
Demand Response	237	258	264	272	282	237	258	264	272	282
Net Internal Demand	37,169	38,653	40,165	41,615	43,269	44,535	45,405	46,053	46,953	47,706
Additions: Tier 1	6,639	7,501	8,155	8,562	8,914	8,914	8,914	8,396	8,852	8,852
Additions: Tier 2	1,771	5,410	6,994	9,369	9,872	11,263	11,286	10,468	11,286	11,252
Additions: Tier 3	2,502	3,899	5,242	7,562	9,710	12,409	14,804	14,801	24,521	24,571
Net Capacity Transfers (WECC Model)	902	2,544	4,162	5,101	6,301	5,895	5,570	4,880	5,030	4,715
Existing-Certain and Net Transfers	45,794	46,457	47,523	49,023	49,986	49,308	47,432	44,294	44,948	43,944
Anticipated Reserve Margin (%)	41.1%	39.6%	38.6%	38.4%	36.1%	30.7%	24.1%	14.4%	14.6%	10.7%
Prospective Reserve Margin (%)	45.8%	53.6%	56.0%	60.9%	58.9%	56.0%	49.0%	37.1%	38.6%	34.3%
Reference Margin Level (%)	13.3%	13.7%	13.6%	12.6%	12.2%	12.0%	11.7%	12.3%	11.3%	11.1%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Southwest Highlights

- ARM remains above the RML through 2034. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM falls below the RML in Summer 2034. With the addition of Prospective Resources, the area can remain above RML.

WECC-Southwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	4,121	4,116	3,749	3,754	3,754
Coal*	3,761	4,116	3,749	3,754	2,576
Petroleum	341	340	340	336	336
Natural Gas	24,978	24,887	24,817	24,837	24,750
Biomass	46	46	46	46	46
Solar	6,867	6,349	6,503	7,474	7,804
Wind	1,059	1,055	1,055	1,059	1,050
Geothermal	1,555	1,555	1,607	1,572	1,454
Conventional Hydro	1,984	1,989	1,989	1,982	1,981
Pumped Storage	113	113	113	113	113
Nuclear	3,641	3,640	3,640	3,641	3,641
Battery	6,824	7,325	7,657	7,671	7,671
Total MW	51,530	51,414	51,516	52,484	52,598
Total MW*	51,170	51,414	51,516	52,484	51,421
***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-Southwest

Planning Reserve Margins
The ARM falls below the RML in Summer 2034 but is covered by the PRM. Arizona Public Service and Public Service Company of New Mexico (PNM) are participants in the WRAP.

Energy Assessment, Including Non-Peak Hour Risk
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

WECC-Southwest does not show any LOLH or EUE in 2027 or 2029; therefore, no additional visualizations are provided.

Demand
The average annual demand growth rate for WECC-Southwest is 3.9%. The primary drivers are data centers, industrial electrification, residential electrification, and residential customer growth. Large-load additions in the forecast are 9,422 MW through 2035.

Demand-Side Management
In the Southwest, Arizona Public Service is in the process of implementing numerous DSM pilots and programs such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. The Residential Energy Storage Pilot enables the company to dispatch a small battery energy storage system up to 20% of the system's capacity.

Salt River Project (SRP) continues to leverage approximately 87 MW of DR capability through more than 75,000 residential smart thermostats, and 41 MW from over 500 businesses enrolled as interruptible customers. SRP intends to achieve 300 MW of dispatchable DR capability by 2035.

PNM programs reduce peak demand by an average of 45 MW per summer event from its two primary programs enrolling the ability to call on commercial customers and residential air conditioners up to 100 hours with a four-hour limit per curtailment.

Distributed Energy Resources
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DER).

Generation
Operational and planning issues related to generation in WECC-Southwest include the following:

- **Aging Thermal Resource Fleet**: A year-round concern for this subregion is an aging thermal resource fleet. Hundreds of MW of capacity in this region have been operational for over 60 years. During the winter, certain thermal resources are unable to cycle below 40°F due to freezing issues. Older sites also require extensive overhauls such as generator rewinds that can keep resources out of service for extended periods of time and potentially longer than planned as discovery work manifests into additional maintenance. To reduce the risk of age-related forced outages, plant staff adhere to a strict maintenance schedule with frequent inspections, and unit performance is routinely monitored.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round as BTM solar can supply a large amount of energy to the system. Unanticipated loss of BTM generation is addressed through activation of DR programs, peaking power plants, and maintaining sufficient BESS charge. Near-term forecasts for BTM output are also made available to system operators so they can pre-emptively dispatch the system as needed.
- **Coal Inventory Shortages:** In-progress fuel conversions of coal to gas create a balancing act of maintaining coal on-site to operate resources while also avoiding excess coal post conversion. This can limit coal resources to minimum output prior to the fuel conversion outage. In addition, site-specific challenges at coal mines have delayed coal deliveries to resources in this subregion. Active management of on-site inventory and procurement of fuel from other sources can mitigate these issues.

- **Gas Fleet Derates:** Gas resources in this subregion can be derated during hot weather in the summer due to ambient conditions. During the winter, gas supply has been cut to plants in this subregion during cold snaps. Near-term monitoring of gas availability along with additional market purchases or fuel switching for capable resources can assist in mitigating supply issues.
- **Solar Variability:** Solar output variability is a concern year-round for this subregion. It is a primary concern on summer evenings as solar output rapidly declines whereas load increases or remains elevated. Activation of DR programs, peaking/flexible power plants, and maintaining sufficient BESS charge are all potential strategies to mitigate this issue. Large changes in solar output can also cause extreme ACE fluctuations, which are addressed using BESS.
- **Electric-Gas Coordination:** Most entities in the area consider electric-gas coordination in long-term planning studies. Resource planning models compare forecasted gas usage on both daily and hourly intervals to firm contractual rights. Gas usage exceeding firm obligations results in unserved energy, which can then be addressed via spot market purchases, short-term gas transport capacity purchases, or the dispatching of other resources. Entities also account for forecasted LDC usage and reduce the available natural gas for electric use by this amount. Resource adequacy models do not yet incorporate gas pipeline constraints, but consideration is being given to how to incorporate these into modeling efforts.

  Procedures to mitigate gas supply issues include anticipating losses of scheduled gas from the supply side, ensuring scheduled pipeline maintenance is accounted for in operations, and maximizing the availability of dual fuel resources. Planning teams also coordinate with operations teams for gas supply issues on a season-ahead basis, and operations can re-dispatch the system as needed to manage fuel shortages. During times of potential freeze-offs, trading practices may also be changed to not overextended firm load requirements. Entities maintain winter and summer readiness plans that are shared between electric system operators and gas pipeline operators to ensure maintenance schedules are aligned. Gas system limitations are made known to electric system operators through routine meetings between system operators and pipeline operators.
- **Renewable Portfolio, Clean Electricity & Emissions Standards:** In the Southwest region, Arizona has an RPS mandate for its electric supply to be 15% renewable by 2025. Separately, APS has committed to ending the use of coal-fired generation after 2031, and the company set a 100% carbon free by 2050 goal. SRP has goals to reduce CO2 emissions per MWh by 62% from 2005 levels by 2035 and 90% by 2050; TEP will stop using coal by 2032 and plans to reduce carbon emissions by 80% by 2035. New Mexico has set more aggressive mandates, requiring 50% renewable by 2030, 80% by 2040, and 100% by 2045.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[49] for the summer and winter of each year.[50] Projected total internal demand is based on normal weather (50/50 distribution)[51] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[52]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-Alberta	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-Basin	Summer	Noncoincident	
WECC-British Columbia	Winter	Noncoincident	
WECC-California	Summer	Noncoincident	
WECC-Mexico	Summer	Noncoincident	

[49] Glossary of Terms Used in NERC Reliability Standards.
[50] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).
[51] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[52] 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.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[52]**	**Load Forecasting Entity**
WECC-Northwest	Winter	Noncoincident	
WECC-Rocky Mountain	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[53]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[54]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[55]

[53] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[54] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[55] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[56]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[57]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[56] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[57] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): 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, system planners use this metric is 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 increased 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/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[58]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[59] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[60] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[61] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[62]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

[58] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[59] BES Definition
[60] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[61] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[62] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

- **Adequate:** The ARM is greater than RML.
- **Marginal:** The ARM is lower than the RML and the PRM is higher than RML.
- **Inadequate:** The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[63] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

- **Normal Risk:** Negligible amounts of LOLH and EUE.
- **Periods of Risk:** LOLH < 2 Hours and EUE < 0.002% of total annual net energy.
- **Significant Risk:** LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.
Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
  - Planned (any of the following):
  - Permits have been approved to proceed

[63] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

- Design is complete
- Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”
  - Other projected lines that do not meet requirements of “Under Construction” or “Planned”

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2025-2026 Summer: 8.1% Fall: 14.9% Winter: 19.1% Spring (2027): 26.2%	Planning Reserve Margin	Yes: Established Annually[64]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[65]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	13.0–13.4%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[66]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	15.8–22.6%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	11.9–12.2%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	18.6–26.3%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[67]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[64] In MISO, the states can override the MISO PRM.

[65] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[66] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[67] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[68]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[69]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[70]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustent for non-modeled market considerations	ERCOT Board of Directors
WECC-Alberta	11.6–17.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[71]
WECC-Basin	12.3–14.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-British Columbia	11.6–12.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-California[72]	19.2–20.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Mexico	7.0–9.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Northwest	15.5–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Rocky Mountain	15.7–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Southwest	12.2–13.7%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]

[68] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[69] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[70] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[71] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[72] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.

2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[73] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[74] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[75] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[76,77]

3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[78] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[79]

[73] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[74] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[75] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[76] NERC IBR Activities
[77] Order No. 901 Work Plan
[78] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[79] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[80]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	Cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and BAs for use in operating plans. Additional Reliability Standard requirements were developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States* and respond to FERC directives.[81] In September 2025, FERC approved EOP-012-3 with an effective date of October 1, 2025. The revised standard strengthens generator preparedness by providing clearer and more effective requirements. In the approval order, FERC also directed NERC to make information fillings to FERC every two years beginning in October 2026 and continuing through October 2034, to assess the adequacy of the standard's ability to address reliability concerns and inform potential future modifications.	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[82] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[80] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[81] Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* and *Project 2024-03 Revisions to EOP-012-2* on NERC's standards development page. Project 2021-07

[82] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered BPS-connected IBRs.[83] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[84]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 1. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
***Interregional Transfer Capability Study* (ITCS)**	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024[85]. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis was published in 2025.[86] See **Interregional Transfer Capability Study (ITCS) Canadian Analysis**.	ERO Study and Recommendations

[83] FERC Order Issued November 17, 2022
[84] RSTC Approved Documents
[85] NERC's *Interregional Transfer Capability Study* (ITCS) Final Report
[86] NERC's *Interregional Transfer Capability Study (ITCS) Canadian Analysis* Final Report

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

2. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

3. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [87]

4. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

5. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[88]

[87] NERC ERS Measure 6 Forward Tech Brief
[88] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2025 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[89] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[90] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[91]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The statuses of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[92]	Reliability Standards Reliability Guidelines Educational Webinars
Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[89] ERAWG
[90] Project 2022-03
[91] Project 2023-07
[92] DER Activities

Errata

February 2026

- Resource mix changes: Corrected natural gas, solar, wind, conventional hydro, battery, and total resource capacity for 2025 in Table 16. Corrected the caption of Figure 16 (p. 30).
- WECC British Columbia: Corrected highlights for BC Hydro's most recent 10-year capital plan (p. 144 and 146), corrected the WRAP participation description (p. 145), corrected the DER programs (p. 145), and included a more current drought outlook from October 2025 in the Generation section (p.145)

EXHIBIT 107

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-18

DECLARATION OF NIKHIL KUMAR
IN SUPPORT OF
MOTION TO INTERVENE, REQUEST FOR REHEARING,
AND MOTION TO STAY BY STATE OF WASHINGTON

I, Nikhil Kumar, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

1. I serve as Program Director at GridLab, a technical non-profit that provides expert capacity and technical leadership to address challenges related to the reliability and evolution of the nation's electric grid.. A copy of my biography and C.V. is attached.

2. In forming the opinions stated in this declaration, I relied on my technical expertise, past experience, and the following documents:

- NERC, *2025 Long-Term Reliability Assessment*, available at: https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf
- GridStategies, *Review of NERC's 2025 Long-Term Reliability Assessment*, available at: https://gridstrategiesllc.com/wp-content/uploads/FINAL-2025-LTRA-Review.pdf
- Sylvan Energy Analytics, *Near-term winter resource adequacy challenges in the Pacific Northwest* (January 2026), available at: https://gridlab.org/portfolio-item/pnw_nearterm_winterra/
- Koomey Analytics, *Separating Fact from Fiction in Data Center Electricity Forecasts: A Guide for Regulators* (March 2026), available at: https://gridlab.org/data-center-load-forecast-report-2/?ref=koomey.com

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

- E3, *Final Report: Resource Adequacy and the Energy Transition in the Pacific Northwest*, available at: https://www.ethree.com/ra-pnw/

- Brattle, Proposed Options for Bilateral Integration of Generation Portfolios and Load (September 2025), available at: https://www.brattle.com/wp-content/uploads/2025/10/Proposed-Options-for-Bilateral-Integration-of-Generation-Portfolios-and-Load-BIGPAL.pdf

- RTOInsider, MISO: NERC to Dial Down RTO's Risk Level, available at: https://www.rtoinsider.com/128949-miso-nerc-will-lower-risk-level-stakeholders-create-large-load-working-group/

3. The North American Electric Reliability Corporation (NERC) Long-Term Reliability Assessment (LTRA) is frequently cited to highlight emerging resource adequacy concerns. However, in the context of the Pacific Northwest (PNW), its underlying assumptions and structural limitations make it an incomplete and overly conservative basis for near-term policy decisions, particularly those involving emergency measures such as extending coal plant operations.

4. Regional analysis confirms that projected adequacy gaps in the PNW are highly sensitive to modeling assumptions. Modest adjustments, such as inclusion of the Centralia Power Plant conversion, hydro flexibility, or demand response significantly reduce or eliminate modeled shortfalls. Importantly, even under conservative assumptions, the LTRA shows no material near-term reliability deficiencies. Projected shortfalls are confined to later years and are highly sensitive to modeling inputs.

5. By design, the LTRA emphasizes risk identification over precise forecasting. This leads to systematic conservatism in how future conditions are represented. NERC's long-term, scenario-based methodology can lag or mischaracterize rapidly evolving system conditions. For example, in the Midcontinent Independent System Operator, NERC's initial LTRA designation of "high risk" was later revised, even as the region addressed emerging challenges such as large load growth and developed expedited processes like the Expedited

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

Resource Addition Study (ERAS) to manage near-term reliability needs. This is an example that the LTRA may not fully capture near-term reliability dynamics. An independent review of the LTRA methodology and PNW specific studies suggests that the LTRA arrives at an outer-bound scenario and cautious outlook by utilizing conservative assumptions. Even under these pessimistic models, the PNW faces no short-term reliability risk.

6. The LTRA represents a snapshot in time and is a foundational tool, but it is not a comprehensive predictive model. It relies entirely on utility reported data submitted at a specific moment. By definition, this bottom-up approach engineers artificially tight resource margins that do not reflect the realistic, dynamic nature of the grid. If NERC were to use different, more realistic assumptions, the identified long-term risks in the PNW would be significantly resolved.

7. The LTRA's methodology creates an inherent imbalance that overstates risk by treating future supply and future demand with different levels of scrutiny:

a. The LTRA only counts "Tier 1" resources (those under construction or with approved planning), ignoring the massive pipeline of "Tier 2" resources that are actively progressing through interconnection queues.

b. But with respect to load growth, the LTRA takes a very different approach. The extent of the PNW's winter resource adequacy challenge is largely dictated by future load growth. This remains highly unpredictable, driven by the dual uncertainties of data center expansion and electrification trends. The LTRA accepts utility load forecasts driven almost entirely by data centers. However, these forecasts suffer from widespread double counting of prospective demand, as developers frequently request power for multiple sites but only build a fraction of them.

c. The net result is a systematic under-counting of future generation resources and a systematic over-counting of future load.

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

8. The LTRA assumes a worst case scenario for grid interconnectedness, which is particularly invalid in the PNW context:

a. NERC's methodology ignores "non-firm" imports, which are historically the primary mechanism regions use to support each other during extreme stress events. Firm imports are contractually guaranteed, those with reserved transmission rights. Non-firm transfers rely on available transmission capacity and are subject to curtailment. In practice, however, non-firm imports play a meaningful role in real-time system operations in the Western Interconnection, and their omission from planning models can overstate resource adequacy risks.

b. The LTRA excludes the benefits of several planned interregional transfer capabilities, which, if accounted for, would resolve many of the seasonal shortfalls identified in the report. In the PNW context, transmission limits, not supply deficits, are the primary bottleneck. Implementing day ahead market designs, market seams solutions, and prioritizing South-to-North transmission upgrades would allow the PNW to capture California's excess winter capacity, significantly mitigating regional risk.

c. The Western U.S. grid is moving toward greater regional coordination through expanded electricity markets with participation from utilities across California, the Pacific Northwest, and parts of the Southwest. The LTRA does not fully reflect the reliability benefits of emerging Western market reforms, including the Extended Day-Ahead Market (developed by the California Independent System Operator) and Markets+ (developed by the Southwest Power Pool). These initiatives are expected to significantly enhance regional coordination, resource sharing, and day-ahead visibility. These markets will enable day-ahead optimization of generation and transmission across a broader footprint,

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

improving the ability to share resources. While this expansion is expected to enhance reliability and efficiency, actual energy transfers during stressed conditions will still depend on transmission availability, market participation, and real-time system conditions.

9. Even if one accepts NERC's conservative assumptions, there is no immediate reliability crisis in the PNW that warrants a section 202(c) emergency order. The LTRA explicitly shows that the Anticipated Reserve Margin for the WECC-Northwest area does not fall below the Reference Margin Level until Winter 2031–2032.

10. Battery storage, wind, and solar deployment in the PNW meaningfully reduce resource adequacy risks and are central to the region's reliability strategy. While individual resources have limitations during prolonged winter events, modeling shows that a portfolio approach, i.e., combining storage, renewables, demand response, and hydropower flexibility significantly reduces or eliminates projected shortfalls under most conditions. Importantly, these resources are being developed in parallel with load growth, making them well-suited to meeting the region's "organic" demand increases, underlying increase in electricity demand, generally based on historical trends that includes everything except "new large loads". As a result, resource adequacy outcomes are dynamic and improving over time.

a. Solar and wind remain the lowest cost resources per unit of energy.

b. Battery storage, in particular, offers the fastest deployment timeline of any capacity resource, making it uniquely suited to address near term reliability needs.

c. The winter capacity value of 4-hour storage depends strongly on how the PNW's massive hydroelectric system is operated. If battery dispatch is co-optimized with hydro dispatch, it can prevent the rapid saturation of short-duration storage and provide significantly more reliability value to the region.

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

11. The long-term risk in the PNW is driven almost entirely by the uncertain influx of data centers. However, this uncertainty should not be treated as an exogenous shock to the system. Utilities in the region retain direct control over interconnection and service decisions, and will only bring new large loads online to the extent that sufficient generation, transmission, and system capacity exist to reliably serve them. In this sense, load growth is endogenous to the resource adequacy framework, not an uncontrollable driver of risk.

12. Rather than extending the life of retiring coal plants, the region can address future winter reliability needs through a combination of prudent load management and flexible resource strategies. If data centers are subject to emergency curtailment agreements during extreme multi-day winter cold snaps, the grid can easily maintain reliability. Modeling of severe winter events in 2030 shows that prioritizing the curtailment of massive data center loads before disconnecting residential customers reduces average customer outages from 19 hours down to just 6 minutes (0.1 hours).

13. In addition, emerging models demonstrate that co-located solutions, such as battery storage paired with large loads can provide firm capacity during peak events, with load curtailment serving as a backstop if storage is depleted. Similarly, many large loads are capable of deploying limited onsite backup generation or behind-the-meter resources to temporarily reduce demand during system stress, further enhancing reliability. These approaches move the focus from building more centralized supply to managing flexible demand, offering a scalable and cost-effective way to meet resource needs.

14. For state regulators in the Pacific Northwest, the LTRA should be understood as a high-level planning signal. It is a valuable report, but only when one considers the assumptions it is built upon. Decisions regarding reliability interventions should be grounded in granular, region specific, and near term analyses, including seasonal assessments, balancing authority studies, and operational planning evaluations that reflect real world system conditions. The LTRA presents a conservative and incomplete view of future system

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

conditions, rather than a balanced assessment of likely outcomes. The LTRA is designed to highlight potential vulnerabilities, not to serve as a forecast of unavoidable shortfalls. Its methodology can under-represent planned generation additions, overstate emerging demand such as data centers, and overlook the operational flexibility enabled by regional power sharing. Given that the Pacific Northwest shows no near-term reliability risk under NERC's own metrics, and that more effective demand-side solutions are available to manage longer-term load growth, the LTRA should not be used to justify short-term resource adequacy emergency actions.

DATED this 13th day of April, 2026, in Berkeley, CA.



NIKHIL KUMAR

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

Nikhil Kumar

Nikhil Kumar is a Program Director at GridLab, a 501(c)(3) dedicated to providing expert capacity and thought leadership to address the technical and reliability challenges of implementing clean energy policies. In this role, Nikhil bridges the gap between complex power system operations and policy goals. In addition to his work at GridLab, he serves as an Operational Director at Intertek. He has supported electric power companies globally on strategic issues, specializing in asset risk, reliability, and operations & maintenance (O&M) costs. Previously, as a business analyst at Ventyx (now Hitachi Energy), Nikhil implemented energy market portfolio management solutions for utility clients across various markets. A recognized industry leader, he received the ESIG Industry Excellence Award in 2020 for his contributions to enabling renewable integration through conventional fleet flexibility.

Technical Project Experience

- Testimony preparation and subject matter expert reports for state commission consideration of power plant costs, unit life and reliability.
- Development of digital transformation and asset management strategy for power generators. Principal consultant on product development for equipment life and damage estimation from operational and integrity data.
- Renewable integration and impact of flexibility on power plant operations and maintenance. Cost of cycling studies for fossil, hydro, and nuclear power plants. Power plant emissions analysis. Impact of plant cycling on emissions.
- Asset Management, Failure Analysis, Reliability and Maintainability, O&M Cost Forecasting for solar, wind and conventional power generators.
- Business and technical analyst on the world's first Integrated Smart Grid City project. Worked extensively in implementing solutions for Demand Response and Distributed Energy Resources.
- Technical due diligence of power generation assets including determining the total cost of generation, maintenance requirements, operational capabilities to assist in flexible generation and plant reliability.
- Assisted major utility clients in preparation for electricity market redesign. Implemented and supported energy portfolio management tools for dispatch planning.
- Lead analyst, specializing in short-term portfolio optimization. Worked on the full life cycle of implementations, including developing implementation project plans, customer requirement specifications, test plans, training programs, and fully configuring and testing software solutions to be used in production.
- Advised the Planning and Risk groups at utilities in advanced risk analytics to evaluate both physical and financial assets.

Select Publications

The Storage Gap, Deployment Challenges in the East, GridLab (2026).

Separating fact from fiction in data center electricity forecasts: A guide for regulators, Koomey et al. (2026).

Asset Management for Sustainable Nuclear Power Plant Operation, IAEA Nuclear Energy Series NR-T-3.33, Vienna (2021).

Update of Reliability and Cost Impacts of Flexible Generation for Western Electricity Coordinating Council, N. Kumar (2020)

Power Plant Cycling Costs, N. Kumar et al., Intertek APTECH Report AES 11077844-2-1 (2012).

Predicting Power Plant Equipment Life Using Machine Learning, M. Gascon et al., JERT-ASME (2019).

Non-Baseload Operations in Nuclear Power Plants: Load Following and Frequency Control Modes of Flexible Operations, Kilic, Arif N. et al., IAEA Nuclear Energy Series No. NP-T-3.23, Vienna.

The Western Wind and Solar Integration Study Phase 2: NREL Report NREL/TP-5500-55588, D. Lew et al. (2013).

Finding Flexibility, Cycling the Conventional Fleet, D. Lew, G. Brinkman, N. Kumar, S. Lefton, G. Jordan, and S. Venkataraman IEEE Power & Energy Magazine (2013).

Reliability, Availability, Maintainability (RAM) For Wind Turbines, N. Kumar et al. PowerEnergy2017-3045, Proceedings of the ASME 2017 Power and Energy Conference (2017)

Impact of Plant Cycling on Availability, N. Kumar, M. Liu (Intertek), M Ouellette K. Miller (Portland General Electric) ASME Power 2015 (2015)

Impact of Large-Scale Wind & Solar Integration on Existing Fossil Generation in United States, N. Kumar et al., 15th Wind Integration Workshop, Vienna (2016)

Reconciling the Past Decade of Gas Turbine and Combined Cycle Fleet Operations, N. Kumar Presentation at Electric Power (2014).

Cost-Benefit Analysis of Flexibility Retrofits for Coal and Gas-Fueled Power Plants: NREL Report NREL/SR-6A20-60862, S. Venkataraman et al. (2013).

Flexible Coal, Evolution from Baseload to Peaking Plant, J. Cochran, D. Lew, and N. Kumar (2013).

A new paradigm – Cycling Operations at Nuclear Power Plants in U.S., N. Kumar et al., ASME 2013 Power Conference (2013).

Increase Reliability and Profitability while Adapting Maintenance to Changing Market Demands, Douglas Hilleman and Nikhil Kumar, Electric Power Conference Session 2D (2016).

Retrofitting Fossil Power Plants for Increased Flexibility, N. Kumar et al., Power2014-32024, Proceedings of the ASME 2014 Power Conference (2014)

Smart Asset Management - Using Real Time Transient Data to Determine Equipment Damage, Maintenance Costs, and Operational Strategy in Power Plants, N. Kumar, et al. ASME 2013 Power Conference (2013).

Power Plant Cycling Measure - Evaluating Historical Cycling to Model Future Grid Operations, N. Kumar et al. IEEE PES General Meeting (2013).

Impacts of Power Plant Cycling on Emissions, N. Kumar, and S. Lefton, Air Quality IX, EERC, Washington DC USA (2013).

The Value of Demand Response to Mitigate Wind Integration Costs in a Smart Grid, N. Kumar et al., ASME Power Conference. (2011).

A View of a Smart Grid enabled Energy Market with increased Wind Energy – Opportunities and Challenges, N. Kumar, and S. Lefton, Proceedings PCIM Europe 2011, Nuremberg Germany (2011).

Renewable integration—Challenges with Reliability and Costs, and Opportunities, N. Kumar, and S. Lefton, Electric Power 2011, Rosemont IL USA (2011).

Select Lectures & Presentations

NARUC-NASEO Initiative Virtual Learning Series: IRP Models and Assumptions, Comprehensive Electricity Planning (2025)

Optimizing Wind O&M, American Clean Power, Operations and Maintenance Safety Conference (2022)

Risk-based equipment life optimization for wind assets, American Clean Power (2021)

Closing Plenary Session, Nuclear and Renewables – A Match Made in Heaven or Hell? ESIG Spring Technical Meeting (2020)

Owner Operator Roundtable, Onshore Wind Energy O&M Cost Trend & Forecast, AWEA O&M and Safety Conference (2020)

Incentivizing Flexibility in System Operations and Recovering the Cost of Flexibility, International Conference on Large-Scale Grid Integration of Renewable Energy in India (2019).

Asset Integrity Management for Aging Wind Turbines, AWEA Windpower (2019).

From Scenarios to the Present – An analysis of the PJM Renewable Integration Study in 2019, EPRI's Flexible Operation Conference (2019).

Coal Generation Flexing Practices to Support Variable Renewable Energy Integration, USAID/India Greening the Grid (GTG) Renewable Integration and Sustainable Energy (RISE) Initiative (2019).

Cost-Benefit Analysis of Flexibility Retrofits, Plenary Session, EPRI's Flexible Operation Conference (2018).

Economics of Power Plant Cycling, RMEL Steam Generation Cycling Symposium (2018)

Use of coal generation as a flexible source to balance variable renewable energy sources USEA/USAID Workshop, India (2018).

Cost of Cycling Fossil Power Plants – What Do You Need to Know and Why, N. Kumar et al., Indian Power Stations - International O&M Conference (2017)

Real-time prediction of equipment failure and cost of operation. M. Gascon, N. Kumar. EPRI Fall Fleetwide Monitoring Group Meeting. White Plains, NY. (2018)

Predictive Analytics of Operating Transients. M. Gascon, N. Kumar. EPRI Fall Fleetwide Monitoring Group Meeting. Chattanooga, TN. (2017)

Effects of Cycling Service on HRSGs: Background and Case Studies, Presentation at EPRI – Boiler Research Interest Group (2015)

High Renewable Penetration Impacts on the Fossil Fleet, Utility Variable Integration Group (UVIG) Fall Workshop (2014).

Power Plant Cycling – Impacts and Costs, N. Kumar Presentation at EPRI Australian Generation Workshop (2014)

Balancing Variable Generation within a Smart Grid Future, Wärtsilä Future Power Systems Workshop (2010).

Short Notice Demand Response (DR) and Energy Storage (ES): With ubiquitous intermittent generation can DR and ES capture 30% + of the $17 billion ancillary services market? CPower SmartTalk Energy Roundtable (2010).

EXHIBIT 107-1

Near-term winter resource adequacy challenges in the Pacific Northwest

A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges

SYLVAN ENERGY ANALYTICS



Sylvan Energy Analytics

January 2026

This work was sponsored by GridLAB

Who we are

SYLVAN ENERGY ANALYTICS

Sylvan Energy Analytics is a boutique energy consulting and software firm based in Portland, Oregon.

We specialize in integrated resource planning, capacity expansion and production cost modeling, resource adequacy, clean energy policy, and utility regulation.

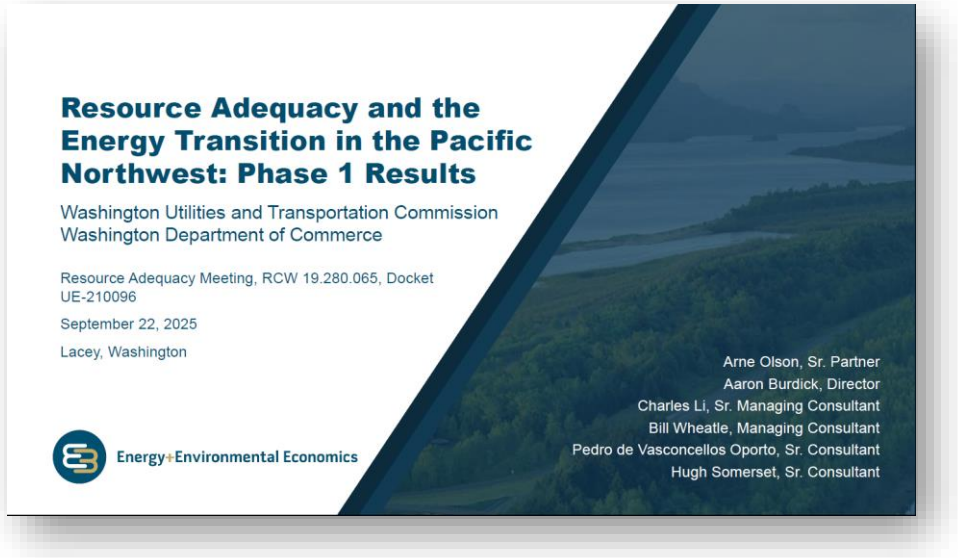
GridLAB

GridLab is a non-profit public interest organization with a mission to provide expertise to enable grid transformation.

GridLab and Sylvan have collaborated on open-source resource adequacy analysis, clean energy planning, and novel resource portfolio optimization techniques.

Background

- In the Fall of 2025, Energy & Environmental Economics (E3) released Phase 1 results of a study examining resource adequacy in the Pacific Northwest
  - The study was sponsored by most of the electric utilities operating in the Pacific Northwest
  - It projected a 9 GW shortfall by 2030 across the "Greater NW," with the potential for multiday supply shortages during winter cold events and shortages as soon as 2026
  - Phase 1 results suggested limited ability for clean resources (wind, solar, and short duration battery storage) to meet the identified needs
  - Phase 2 is underway and is expected to be released in early 2026
- Given the urgency of the Phase 1 findings, Sylvan was engaged by GridLab to review E3's analysis and findings and identify near-term opportunities to support regional RA



Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from "In-Development" Firm Resources	-	296	407	580	770	1,114
ELCC from "In-Development" Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

We would like to thank E3 and the study sponsors for their time and attention in answering our questions

Overview

Problem statement: If we take the E3 study Phase 1 results at face value, the region needs solutions well before significant amounts of new infrastructure can come online

Objective: Understand what drove E3's Phase 1 findings and explore the potential contributions of near-term solutions that may not be considered in Phase 2 of their analysis

Scope:

- Conduct a methodological review in key areas that could impact RA results, including large load flexibility, hydro dispatch flexibility, imports & coordination with California, and retirements & conversions
- Conduct an independent evaluation of the near-term winter RA challenge in the Pacific Northwest
  - Develop multiple load scenarios based on recent load trends and various projections of future data center demand
  - Examine winter resource adequacy challenges in 2030 based on the weather and hydro conditions experienced in January 2024 (the most recent example of highly constrained winter conditions in the Pacific Northwest)
- Identify near-term opportunities to support regional resource adequacy based on findings



Executive Summary

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High
Hydro flexibility	• E3 study may underestimate weekly energy shifting available from hydro dispatch • E3's load following hydro dispatch assumption may overlook contributions from short-duration storage	Uncertain (requires further study)
Imports and coordination with California	• E3 study assumptions may slightly underestimate import winter capability • Winter import capability is limited by transmission, not generation (California has several GWs of unused gas capacity available during PNW winter events)	Low
Retirements and conversions	• Phase 1 results slightly overstated RA challenges by treating coal-to-gas conversions as retirements in initial need evaluation • E3 study Phase 1 did not include Centralia coal-to-gas conversion (it had not yet been announced)	Low-to-moderate

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High

Because of the high potential near-term impact of large load flexibility, most of our analysis focuses on these two highly related questions:

1. How much of the projected need is being driven by data centers (i.e., “new large loads”)?
2. What is the potential for management of new large loads to avoid the most catastrophic consequences of potential supply shortages during extreme weather conditions?

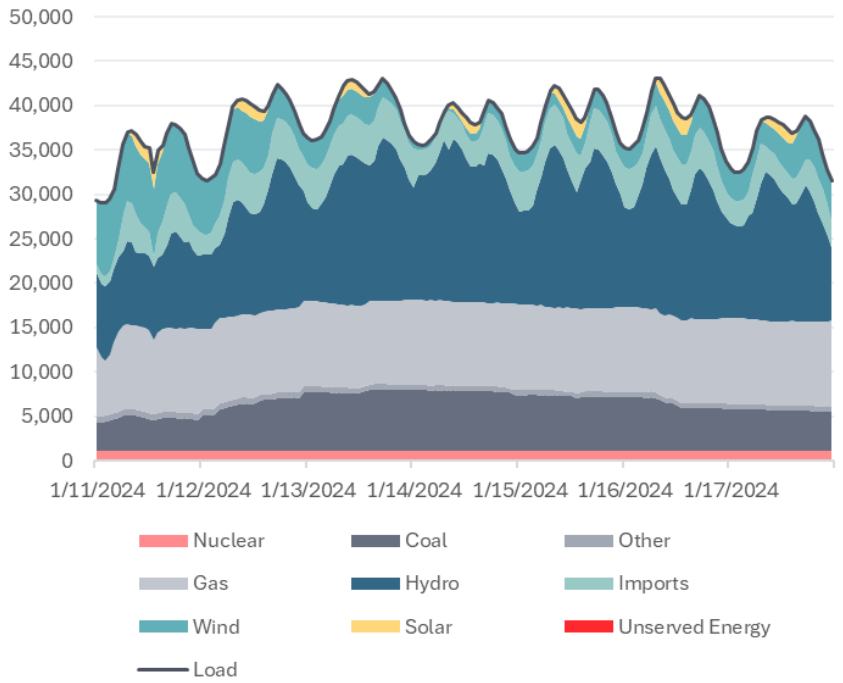
Independent evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

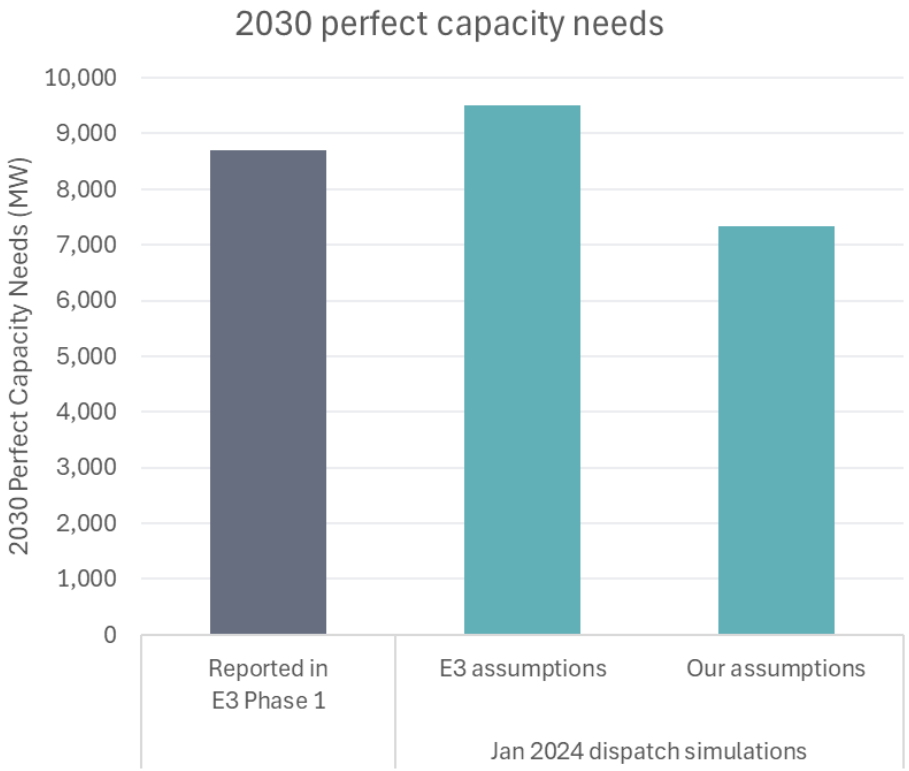
1. Developed dispatch simulation for the "Greater NW" that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
   - Resources in development
   - Emergency large load management
   - Additional proposed clean resources

Simulated dispatch in January 2024 benchmarking run



Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
  - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
  - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas), except Centralia 2
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



Alternative 2030 load scenarios

We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			*1.3%*

All alternative load scenarios envision accelerated load growth relative to the last 6 years

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Finding #1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends

We estimate winter capacity needs in 2030 of 1.0 GW – 4.9 GW after accounting for coal-to-gas conversions and resources in development

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	Reported by E3 in Phase 1
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

Finding #2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios

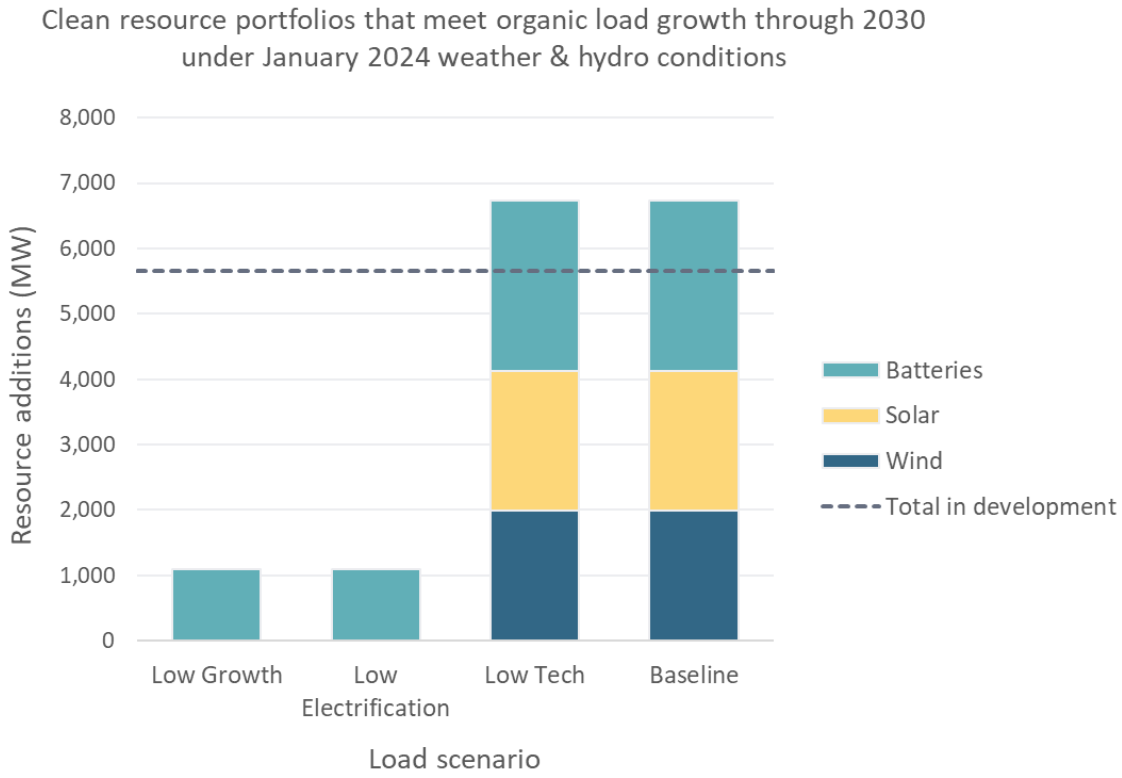
We estimate winter capacity needs in 2030 of 0.0 GW – 3.1 GW to avoid supply shortages if large loads are managed during the most critical winter weather events

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	Reported by E3 in Phase 1
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW
+ Large load flexibility	0.0 GW	0.0 GW	1.1 GW	1.2 GW	3.1 GW	NA

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

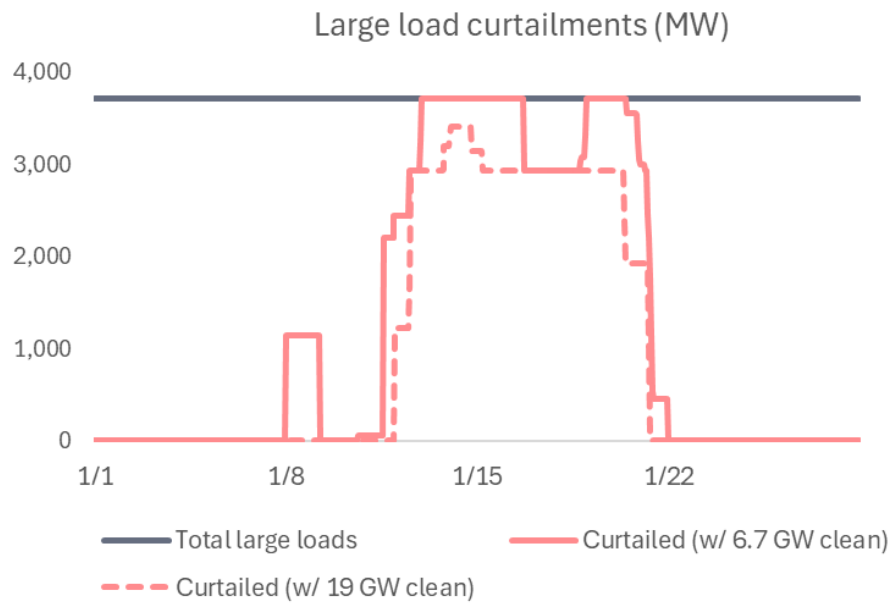
Finding #3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest

- We estimate that less than 7 GW of new wind, solar, and batteries are adequate to avoid supply shortages among non-data center customers under January 2024 weather & hydro conditions in 2030 across our four load scenarios
- Under the E3 Load Forecast Approximation (with more electrification and fewer data centers than our load scenarios), supply shortages cannot be avoided even if all proposed clean resources (19 GW) come online by 2030



Finding #4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events

Without these additional resources, we estimate that large load curtailments could range from 0 hours to 9 days under January 2024 weather & hydro conditions, depending on the load scenario and clean resource buildout



Load scenario	Large load curtailments in 2030 under January 2024 weather & hydro conditions
Low Growth	0 hrs
Low Electrification	2.5 - 4.6 days
Low Tech	2.3 - 6.2 days
Baseline	7.0 - 9.3 days

Note: Clean resource additions range from the greater of the resources under development and the resources needed to meet organic load growth to all proposed clean resources as of December 2024 (19 GW)

Finding #5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages

We estimate that large load management could reduce average outages among other customers during critical winter weather conditions from 19 hours to 0.1 hours (assuming only resources already in development come online by 2030)

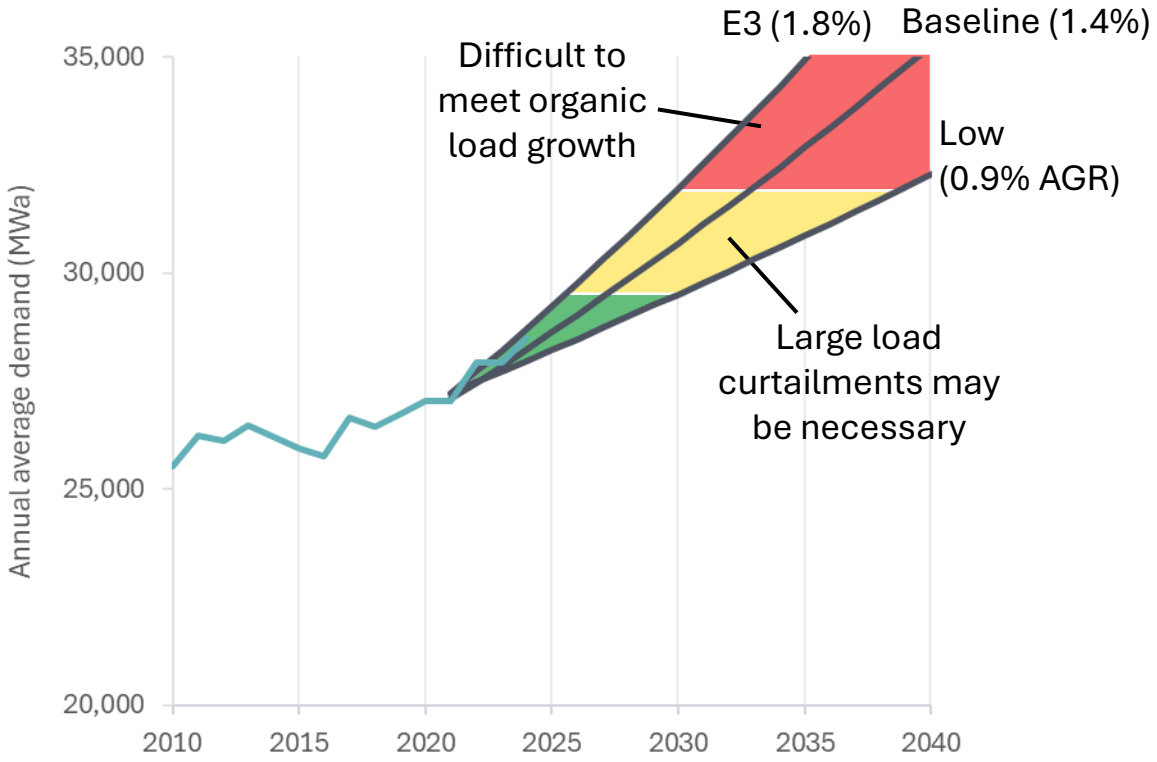
Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario
(assuming only resources already in development come online)

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	**19 hrs**	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Finding #6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency)
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

Extrapolated* organic load growth trajectories and resource adequacy challenges





Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

Near-term opportunities identified to support regional RA

Policy

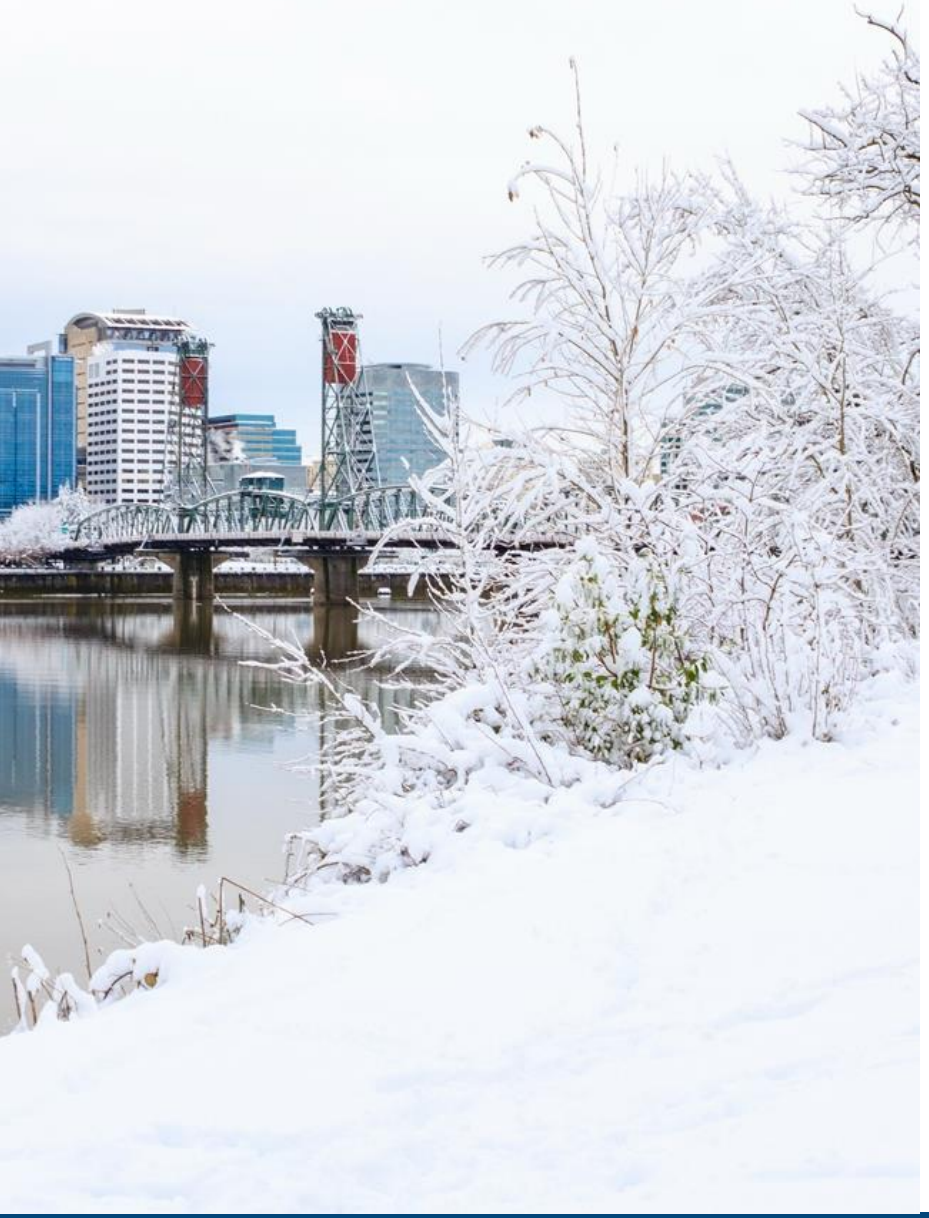
- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages

Planning & Development

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)
- Prioritize transmission studies and upgrades that support increased South-to-North flows into the Pacific Northwest during the winter
- Schedule coal-to-gas conversion activities to minimize winter downtimes
- Study impacts of natural gas system constraints on electricity reliability

Operations

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest
- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits



Analytical Details

Evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

1. Developed dispatch simulation for the Pacific Northwest that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
   - Resources in development
   - Emergency large load management
   - Additional proposed clean resources

Some technical notes

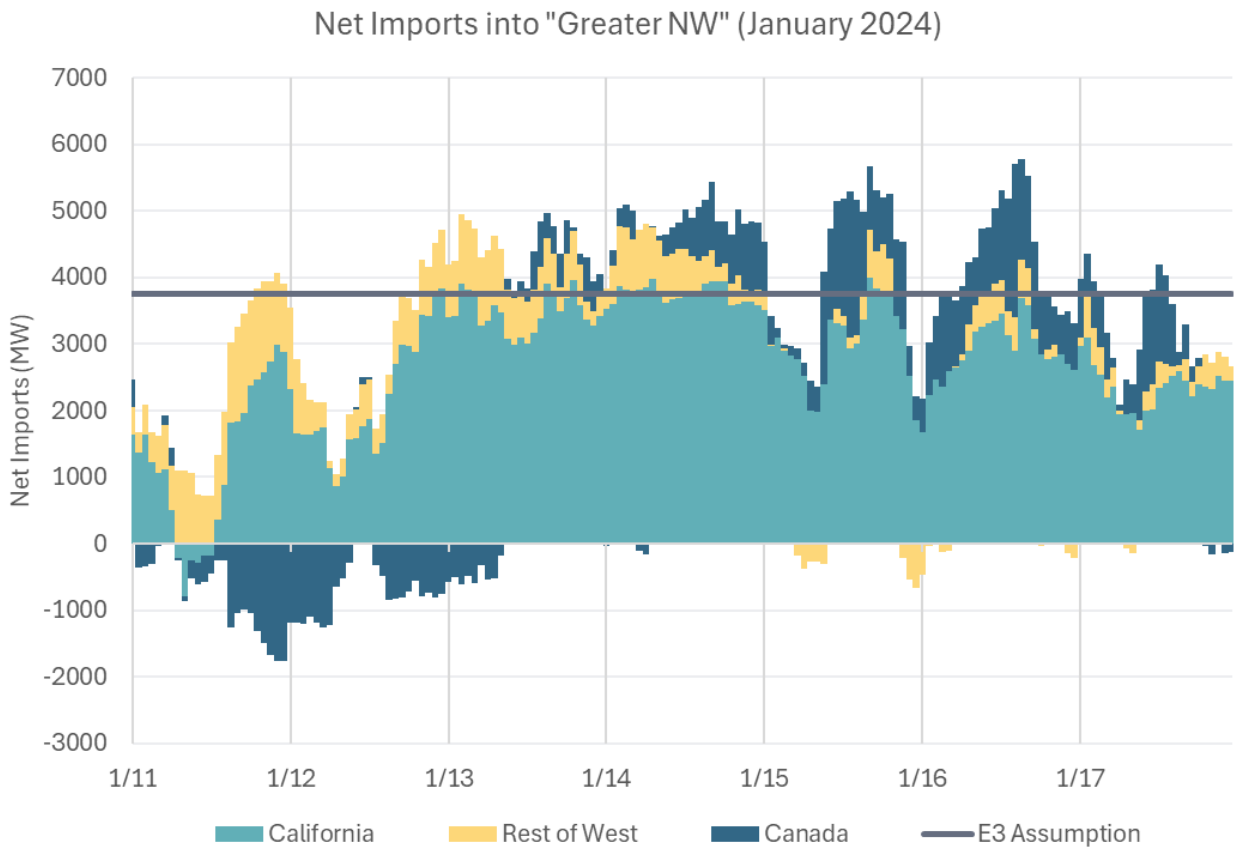
- We did not model full economics due to limited time and data availability, so results are more indicative of what the system *could* do vs. what it *would* economically do
- We have not fully reconciled our "Greater NW" footprint with E3's due to time and data limitations. Loads and resources likely differ between the analyses and load comparisons focus on load growth rates rather than total loads to account for these differences
- Perfect capacity needs were identified by minimizing the maximum observed unserved energy across the month
- Potential customer outages were identified by equally penalizing total and maximum unserved energy to better reflect operations

Key assumptions

	Our analysis	E3 study
Footprint	BAs in OR, WA, ID, MT + PACE	BAs in OR, WA, ID, MT (excluding WAUW) + PACE
Hydro dispatch	Optimized with weekly energy budgets, minimum, maximum, and ramping constraints based on Jan 2024 hydro dispatch; unconstrained energy shifting allowed between weeks 2 & 3	Load-following heuristic with weekly budgets with up to 5% inter-week energy shifting, minimum and maximum levels based on historical min/max as a function of energy budget
Transmission constraints	2024 benchmark: Constrained flows between PACE and PNW based on high and low observations across January 2024 historical observations 2030 simulations: Added 1,000 MW bidirectional capacity associated with B2H by 2030 (total in 2030: -1,150 MW to +3,410 MW)	None in RA analysis (zonal results are from separate simulations, each assuming a copper plate)
Import constraints	Total: 5,000 MW Into PNW zone (excluding Canada): 3,000 MW Canada to PNW: 1,000 MW Into PACE: 1,000 MW	Total: 3,750 MW
Canadian entitlement	2024 benchmark: 660 MWa net exports into Canada across the month, but allowing Canadian storage to also support imports in any given hour 2030 simulations: Same, but net exports reduced to 590 MWa	590 MW exports to Canada in all hours, no accounting for Canadian storage or import capability from Canada
2030 baseline resource fleet	Existing based on operational resources as of January 2024 (EIA 930), in development resources based on 2024 EIA 860 Dave Johnston 3 retired Coal-to-gas conversions of Centralia 2, Dave Johnston 1 & 2, Naughton 1 & 2	Existing and in development resources based on WECC ADS Dave Johnston 3 and Centralia 2 retired Coal-to-gas conversions of Dave Johnston 1 & 2, Naughton 1 & 2 (however in initial need evaluation, these are retired)
2030 Load	Four load scenarios that combine different outlooks for organic load growth and data center demand, plus a load scenario that approximates E3's forecasted load growth	PATHWAYS-based bottom-up loads with adjustments and internal data center forecast

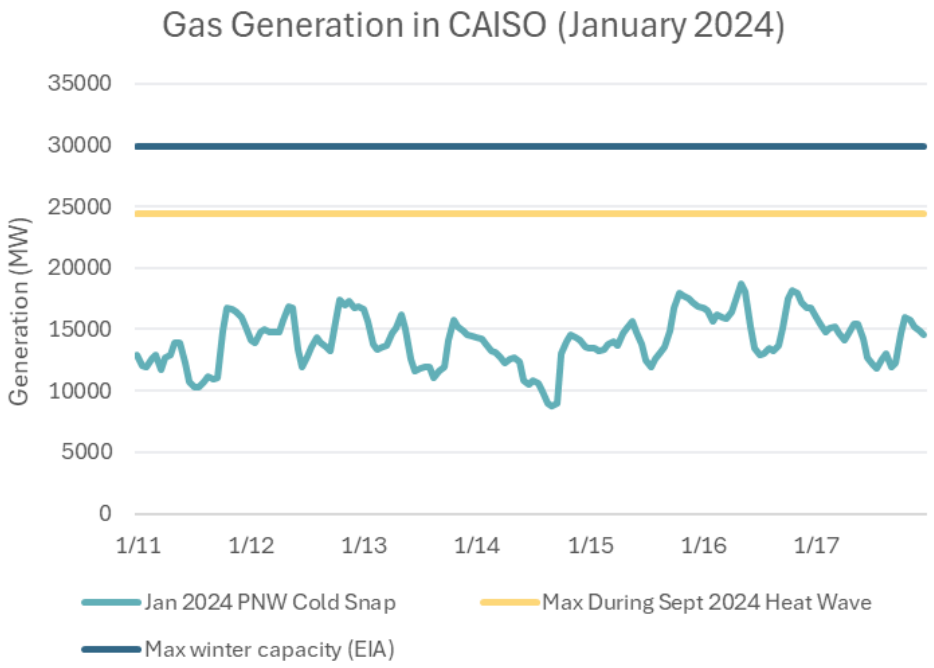
Winter import constraints

- The E3 study assumes 3,750 MW of imports are available in all hours based on imports during the January 2024 cold event
- Net imports into the “Greater NW” exceeded 3,750 MW in 102 hours in January 2024 and exceeded 5,000 MW in the most constrained hours
- The 3,750 MW limit aligns well with imports from California during the event, but may neglect additional import capability from Canada and the rest of the West



Transmission, not available supply, limited imports

- Much of the gas fleet in California went unused during the January 2024 event (i.e., there was not a shortage of regional generating capacity in the West)
- However, South-to-North transmission flows between California and the Pacific Northwest were constrained by operating limits
- South-to-North operating limits on COI and PDCI are tighter than North-to-South limits
  - Max N-to-S during Sept 2024 heatwave: ~5,500 MW
  - Max S-to-N during Jan 2024 cold snap: ~3,800 MW



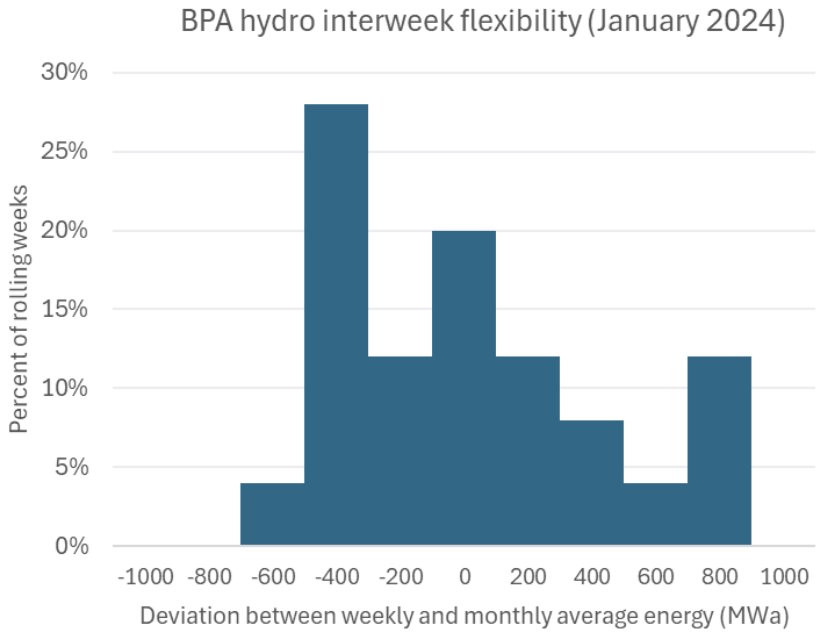
Near-term opportunities to support increased imports during winter events:

- ➢ Prioritize transmission studies and upgrades that support increased S-to-N flows into the PNW during the winter
- ➢ Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest

Hydropower dispatch

Study review:

- E3 confirmed that they use a load-following heuristic to estimate hydro dispatch in each week and they allow 5% of weekly hydro energy to shift between weeks
- Heuristic dispatch may underestimate the potential of the hydro system to support resource adequacy and may overlook opportunities to co-optimize between hydro and other resources, including short-duration batteries
- Analysis into BPA hydro dispatch in January 2024 suggests that any given week could have access to as much as 880 MWa (14%) of additional hydro beyond the monthly average energy



Outstanding substantives questions:

- How do hydro operators value stored water when dispatching their hydro fleets? Does it adequately account for the value of supporting winter reliability over longer timescales (i.e., future days, weeks, or months) or is hydro dispatch over-optimized for short-term economics?
- How will day-ahead market participation affect this tradeoff between short-term revenues and winter reliability value?

Near-term opportunity:

➢ Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits

Retirements and conversions

Study review:

- E3 confirmed the 8,689 MW identified need assumes that coal plants retire instead of undergoing coal-to-gas conversions
  - E3 analysis suggests that capacity needs could be 850 MW smaller with coal-to-gas conversions included

Our approach:

- Include all announced coal-to-gas conversions to avoid over-stating incremental needs
  - While conducting the analysis, Transalta announced the conversion of Centralia 2 to gas. This update was incorporated into our final simulations.

	Winter Capacity	E3 initial need evaluation	Our analysis
Dave Johnston 1	99 MW	Retired	Converted to gas
Dave Johnston 2	106 MW	Retired	Converted to gas
Dave Johnston 3	220 MW	Retired	Retired
Naughton 1	156 MW	Retired	Converted to gas
Naughton 2	201 MW	Retired	Converted to gas
Centralia 2	670 MW	Retired	Converted to gas
Total retired		**1,452 MW**	**220 MW**
Total converted to gas		**0 MW**	**1,232 MW**

Outstanding substantive question:

- Some of PacifiCorp's coal-to-gas conversion plans suggest winter downtimes, which may be avoidable by pushing the schedule out or accelerating it by a matter of months. How does winter reliability factor into scheduling for coal-to-gas conversions?

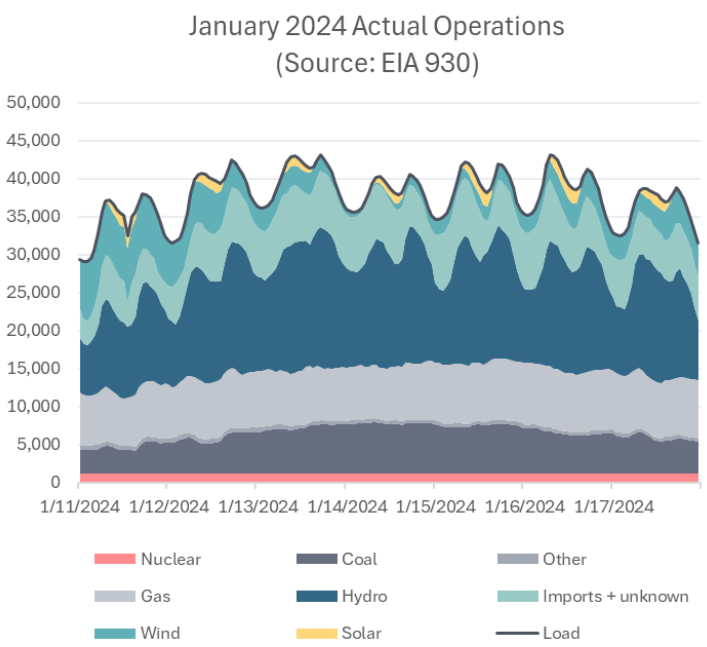
Near-term opportunity:

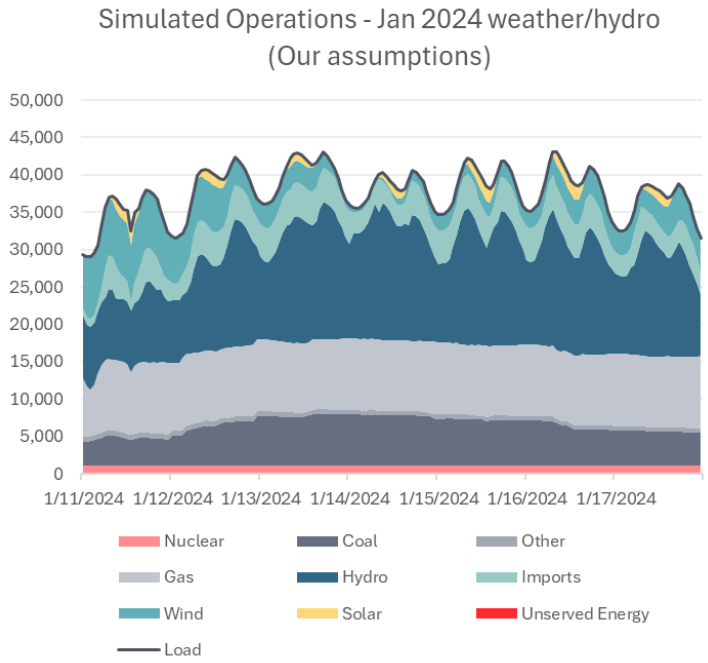
➢ Schedule coal-to-gas conversion activities to minimize winter downtimes

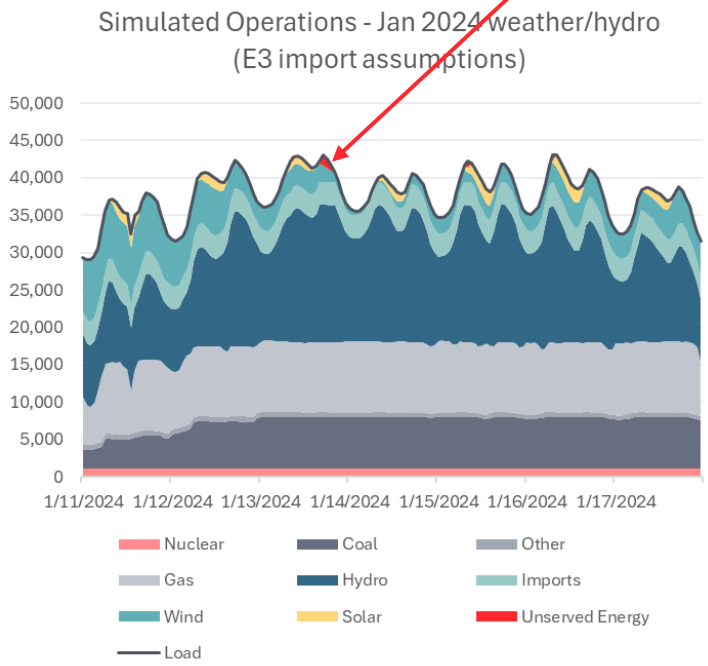
2024 benchmarking

- Tested reasonableness of assumptions by simulating January 2024 dispatch

Applying E3 import constraint yields shortages in 11 hrs, up to 1,400 MW



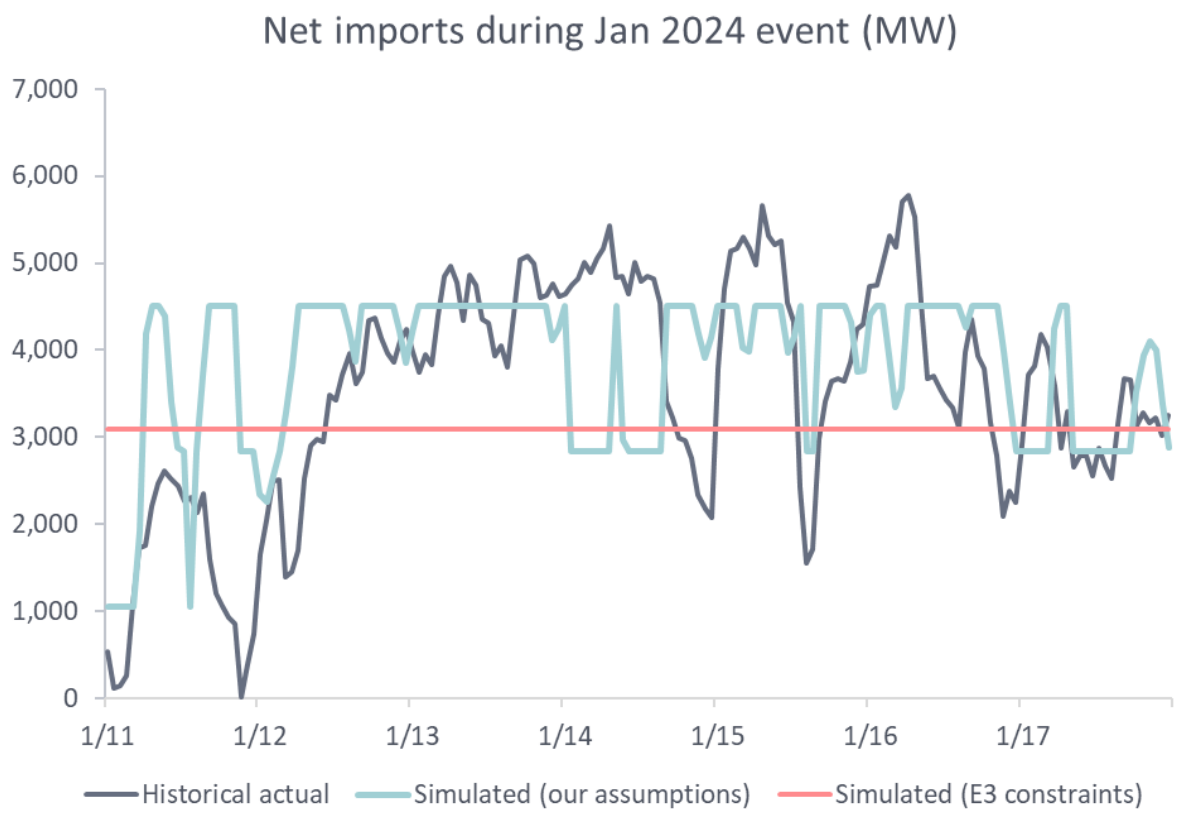




*Actual and simulated operations have different classifications for some resources that are interconnected to BPA, but not reported by BPA (or other BAs) in EIA 930. These resources are simulated explicitly and grouped by technology in the simulated operations plots, but fall within "Imports + unknown" in the actual operations plot (on the left)

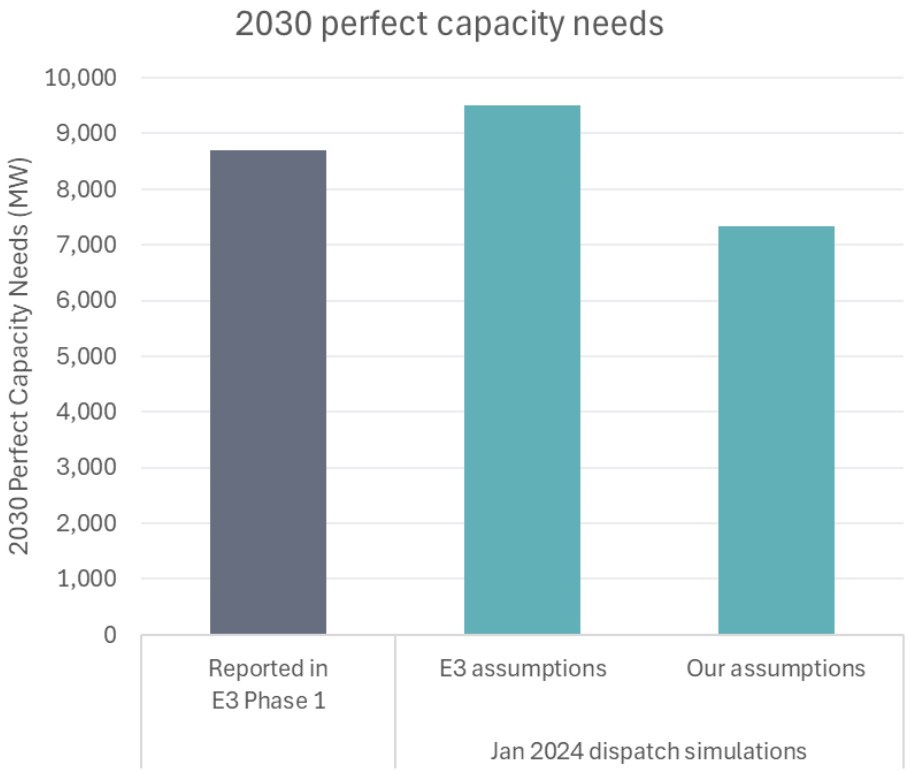
2024 benchmarking

- Additional imports in our assumptions are adequate to clear unserved energy in Jan 2024 benchmarking exercise
- Average net imports between 1/11 and 1/17 are similar across historical actuals and simulations:
  - Historical actuals: 3,508 MW
  - Dispatch simulation with our assumptions: 3,811 MW
  - Dispatch simulation with E3 constraints: 3,090 MW
- Reminder: simulations reflect system capability, not fully economic dispatch



Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
  - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
  - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas, except Centralia 2)
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



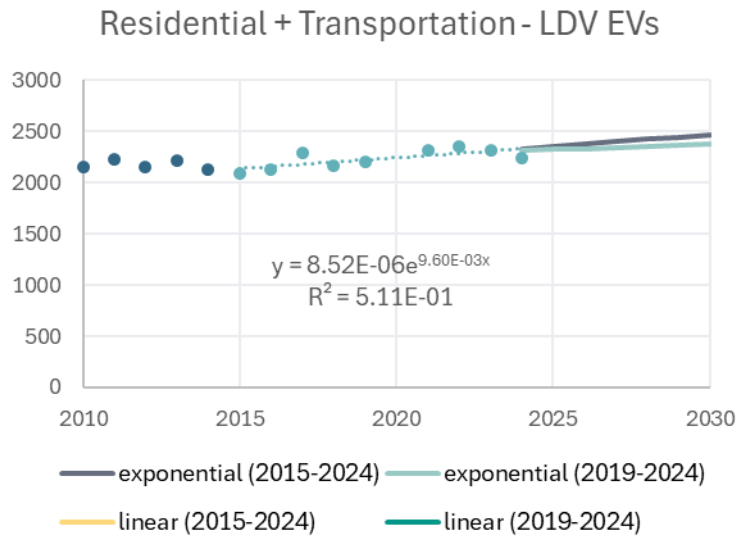
Electricity demand scenarios for 2030

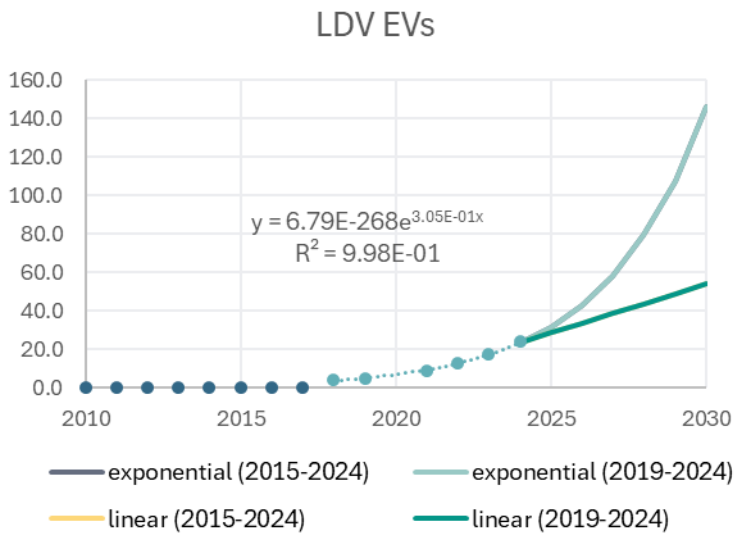
- The E3 study relies on E3's internal load forecast, which comes from their bottom-up PATHWAYS model and internal data center demand forecasts
- E3's annual energy tracks closely with PNUCC's 2025 forecast (with aligned footprints), which is based on utility forecasts and projects 3.2% annual growth
- Data centers vs. electrification
  - E3 suggests that their forecast includes higher EV and electric space heating than the PNUCC forecast, which is potentially offset by a lower data center forecast
  - PNUCC has not collected information from their members to clearly distinguish between organic load growth and data center loads
- To understand the sensitivity of 2030 resource needs to future load growth and data center flexibility, Sylvan developed additional top-down load growth scenarios from available public data

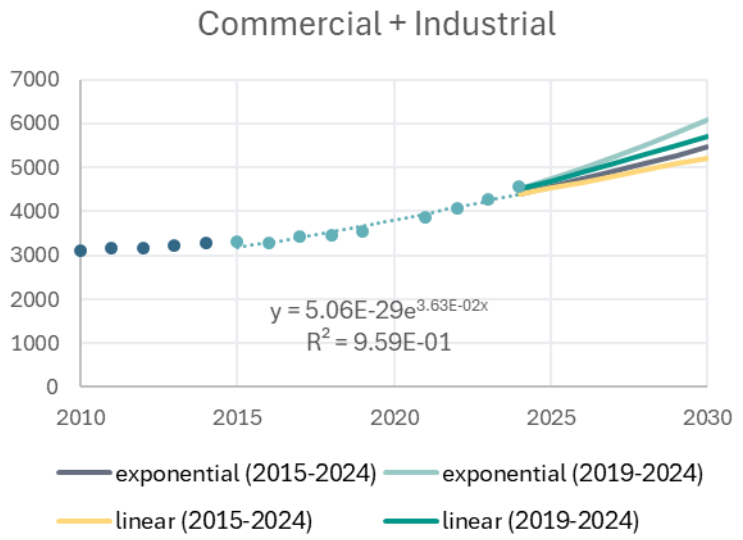
Estimating organic load growth trends

- "Organic" load growth includes everything but new large loads (i.e., includes electrification)
- We estimated plausible ranges of sector-specific loads by fitting linear and exponential functions to recent historical sector-specific loads
- Data sources: EIA historical sales by sector and state, EIA historical LDV EV electricity consumption by state

Example: estimation of organic load growth trends in Oregon







Organic load growth scenarios

- **Baseline organic load growth:** upper bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls between NWPCC "Mixed bag" and "Persistent high growth" load scenarios (excluding data center and H_2 demands)
- **Low organic load growth:** lower bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls just below NWPCC "Mixed bag" load scenario (excluding data center and H_2 demands)
- Note: comparisons are high level and indicative, as footprints vary between forecasts and NWPCC loads assume fixed energy efficiency

Scenario	Average annual organic growth rate through 2030
NWPCC[2] "Persistent high growth"	~1.9%
E3 Forecast[1]	~1.8%
Baseline Organic Growth	**1.4%**
NWPCC[2] "Mixed bag"	~1.0%
Low Organic Growth	**0.9%**
NWPCC[2] "Persistent low growth"	~-0.1%

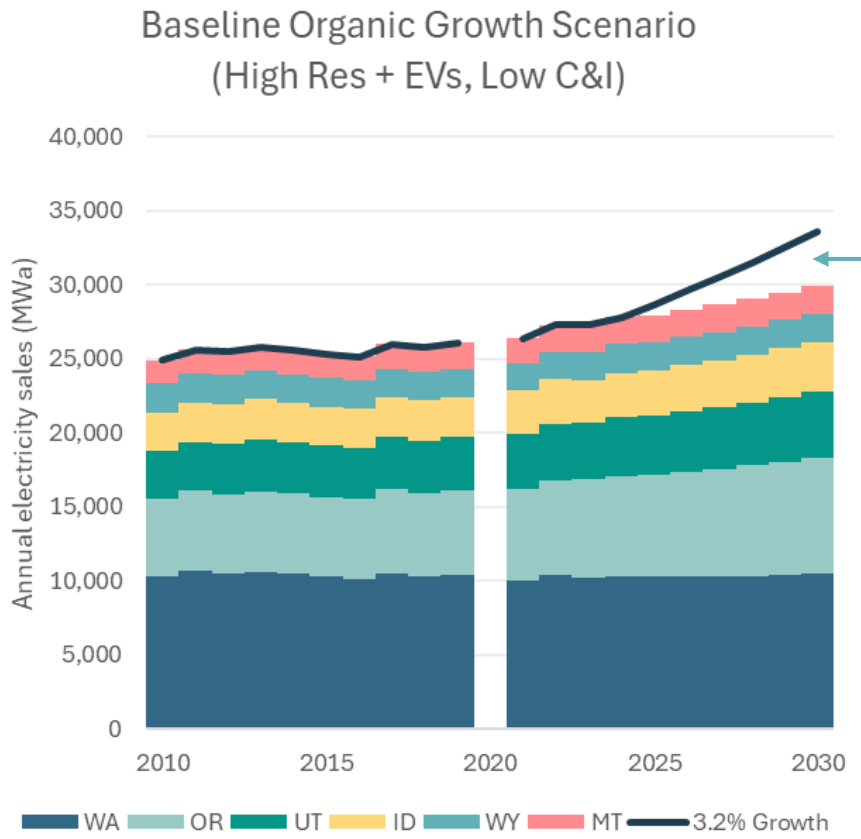
[1]E3 organic growth rate between 2025 and 2030 estimated by subtracting data center demand from total forecasted Greater NW demand reported on slide 24 of Phase 1 Executive Summary

[2]NWPCC growth rates between 2025 and 2030 estimated by subtracting data center and H_2 demand on slide 33 from total forecasted demand scenarios on slide 46 of the Ninth Plan Demand Forecast Part 2 (https://www.nwcouncil.org/fs/19380/2025_0429_2.pdf)

Data center demand scenarios

- **Baseline data center demand:** estimated as the difference between the organic load growth forecast and 3.2% total load growth reported by PNUCC
  - Higher than E3 forecast, between Mid and High forecasts from the NWPCC
- **Low data center demand:** E3 data center forecast

Scenario	PNW MWa (WA, OR, ID, MT)	"Greater NW" MWa (PNW + UT + WY)
Baseline Scenario	**2,931**	**3,717**
Low Scenario (E3 Data Center forecast)	**1,100**	**1,700**
NWPCC Low Tech Load	~1,400	NA
NWPCC Mid Tech Load	~2,200	NA
NWPCC High Tech Load	~4,600	NA



Alternative 2030 load scenarios

We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			*1.3%*

All alternative load scenarios envision accelerated load growth relative to the last 6 years



Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges



Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

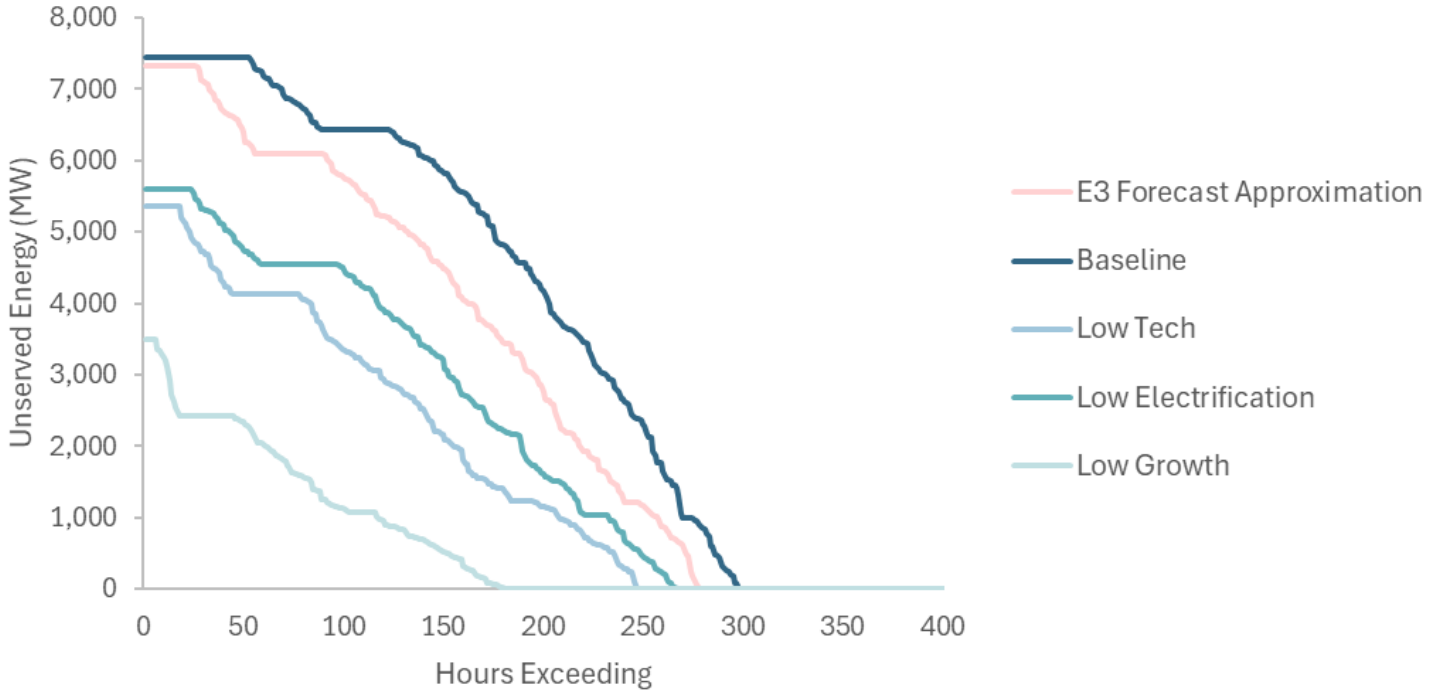
Our findings generally corroborate E3's high level problem statement

Across all load scenarios, unserved energy is observed in large quantities and in several hours if there are no resource additions through 2030, similar to E3's findings

Notes:

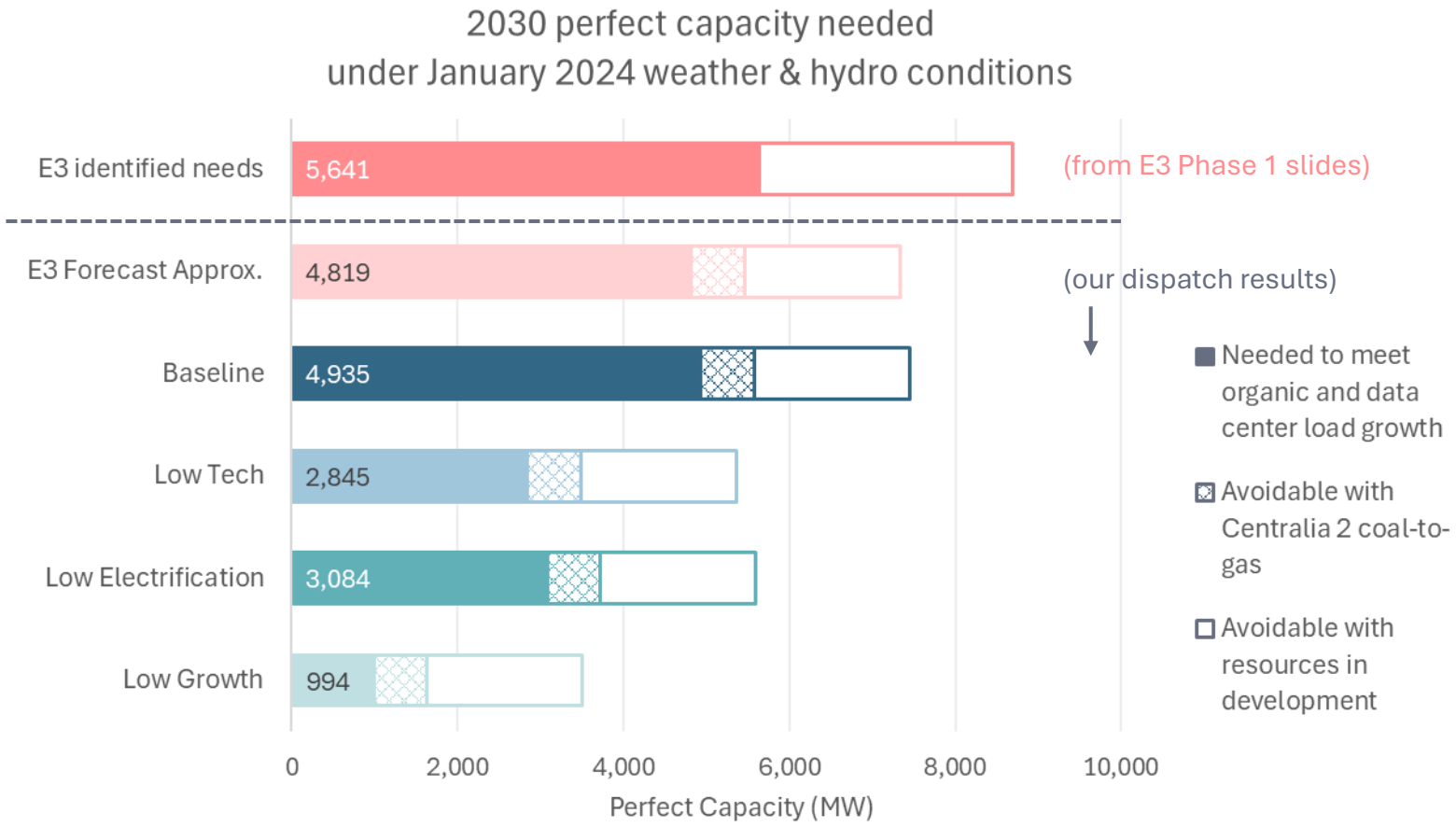
- These results are based on "operational" runs, in which both total and maximum unserved energy are penalized
- Perfect capacity needs (coming up on the next slide) are calculated by minimizing the maximum unserved energy, which can be lower than the maximum values shown on this slide

Simulated unserved energy (sorted from high to low) with no resource additions, before Centralia 2 coal-to-gas conversion



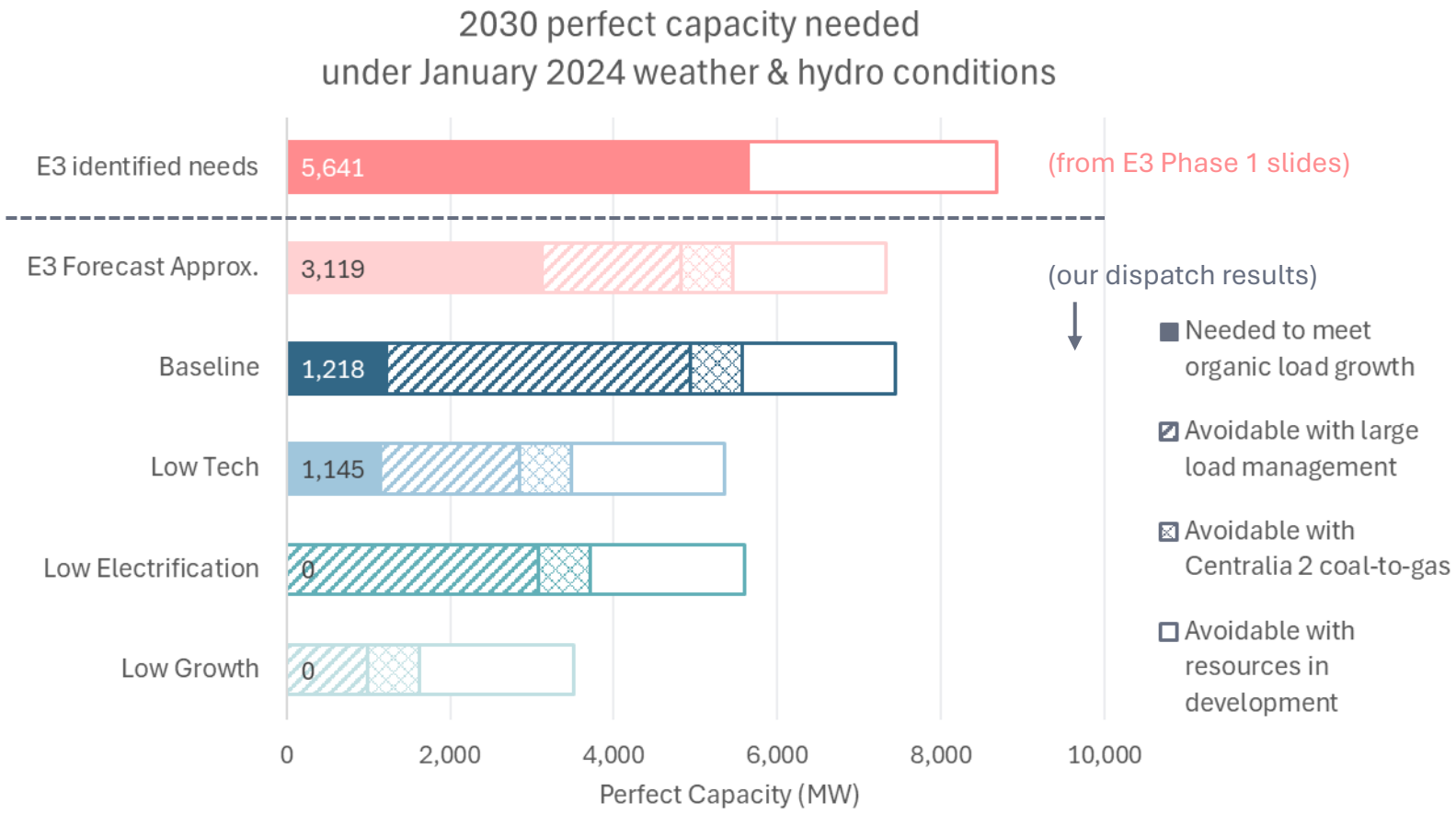
How sensitive are 2030 resource adequacy needs to future load growth?

- No analysis can predict the future and resource needs in 2030 remain highly uncertain, due both to new large loads and electrification trends
- After accounting for resources already under construction or with regulatory approvals in place as of December 2024 according to EIA 860 (“in development”) and coal-to-gas conversion of Centralia 2, estimated remaining 2030 needs range from 1 GW to 5 GW of “perfect capacity” across load scenarios



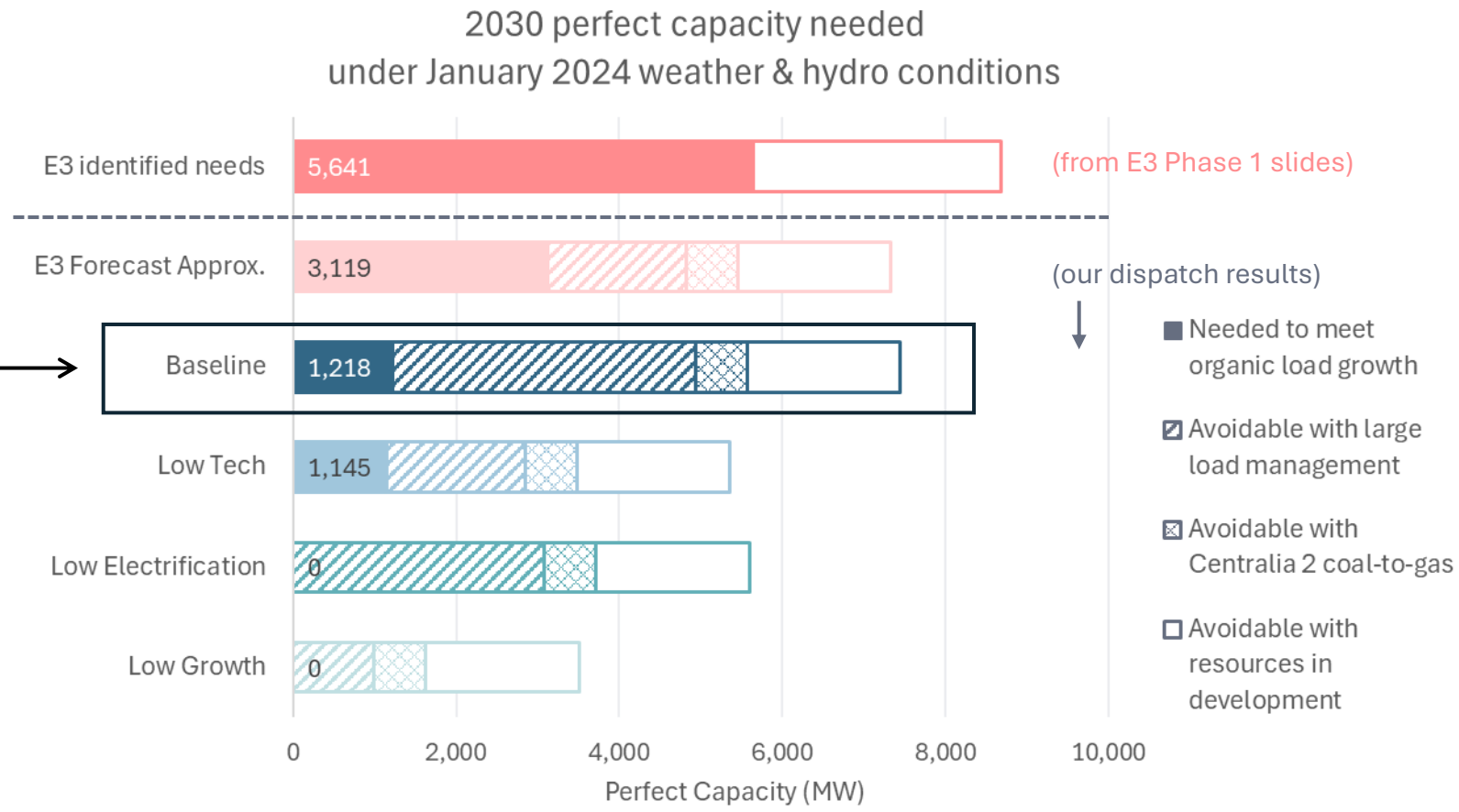
“Connect and manage” for large loads and resource adequacy

- Large loads, which remain highly uncertain in terms of both whether they will materialize and how long they will persist on the grid, are a key driver of near-term needs
- If large loads are interconnected before adequate supply is secured, emergency large load curtailment during extreme weather could mitigate risks to other customers, similar to new requirements in Texas
- If large loads can be managed during extreme weather events, estimated remaining 2030 needs range from 0 GW to 3 GW, depending on organic load growth (including electrification)



“Connect and manage” for large loads and resource adequacy in the Baseline Scenario

Let’s dig further into the Baseline Load Scenario →



Supply shortages from the customer's perspective

If no additional resources are secured beyond those already in development, what does the shortage under the Baseline Scenario look like from the customer perspective during this event?

Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	**19 hrs**	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Near-term opportunity:

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages
  - Could be paired with bring-your-own generation strategies
  - Could enable more rapid interconnection

*Resources in development were either under construction or had final regulatory approvals in place as of December 2024



Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

Addressing supply shortages with new clean resources

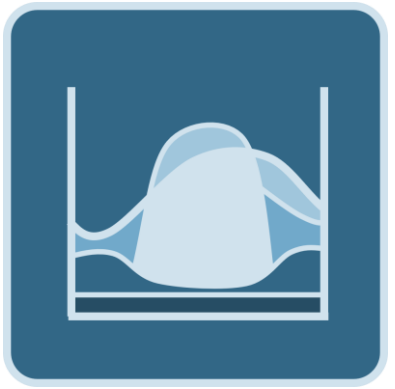
- Next, we allowed the model to select additional resources from projects that were proposed but did not have regulatory approvals (as of December 2024) to meet demand across the January 2024 weather/hydro conditions under the Baseline Load Scenario
  A. To meet organic load growth; and
  B. To meet all load growth, including data center demand
- Findings are broadly indicative
  - Resource costs were high level and imprecise (i.e., these are not optimal selections)
  - Assumed proposed projects have the same hourly availability as existing projects by technology and zone (i.e., understates diversity benefits)

Blended production cost/capacity expansion mode

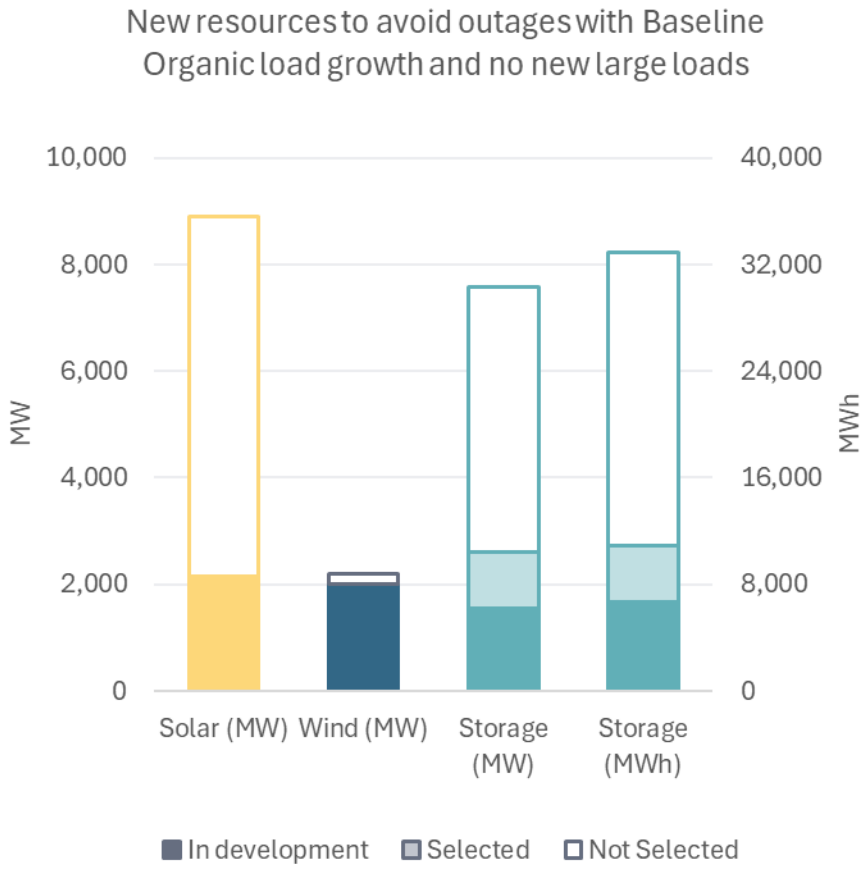
GridPath

Incorporates investment variables directly into production cost problem to probe resource needs and identify potential solutions

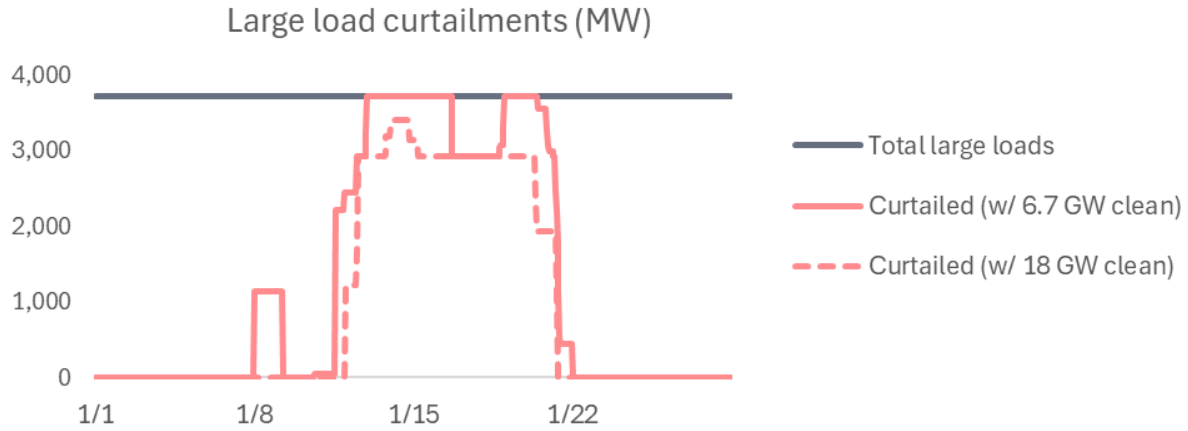




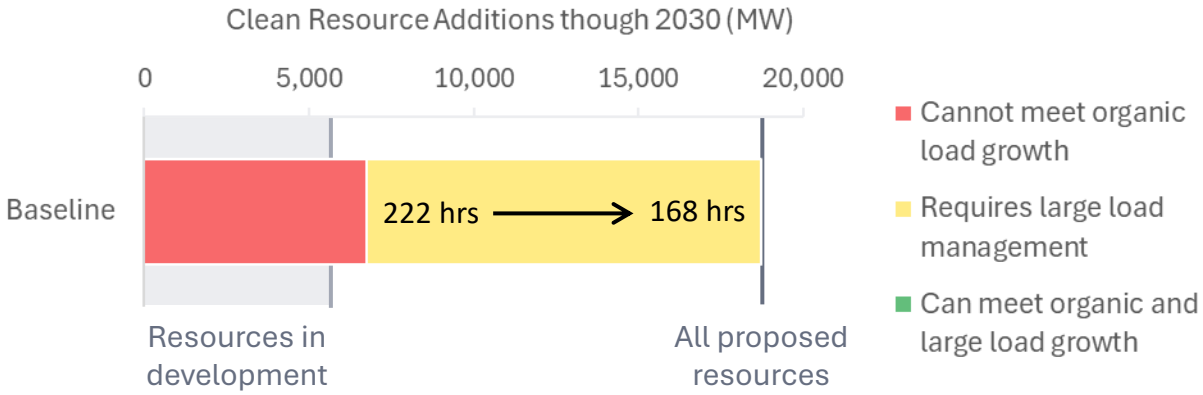
Clean resource additions and large load management in the Baseline scenario



- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- With these additional selected resources: large loads experienced 222 hrs (9.25 days) of outages during the event
- When all proposed clean resources were included (19 GW total): large loads still experienced 168 hrs (7 days) of outages during the event

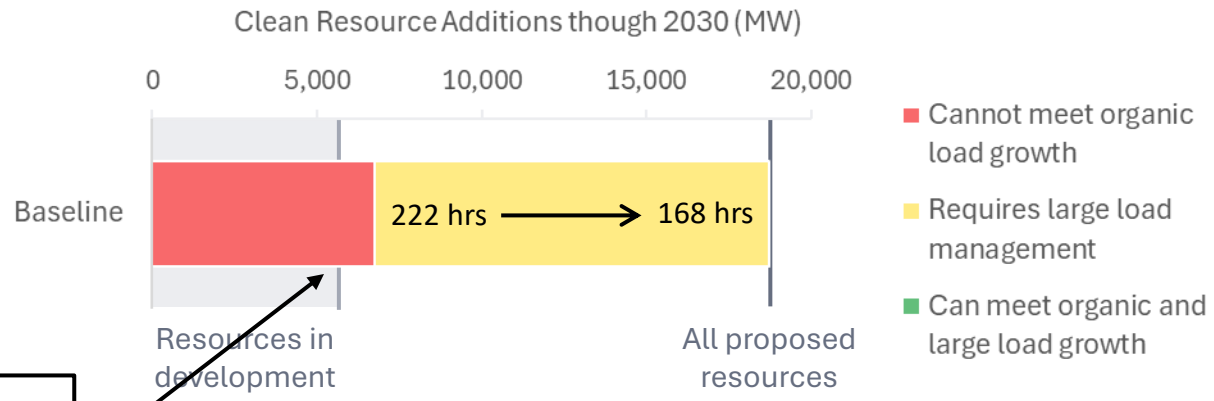


Clean resource additions and large load management across the scenarios



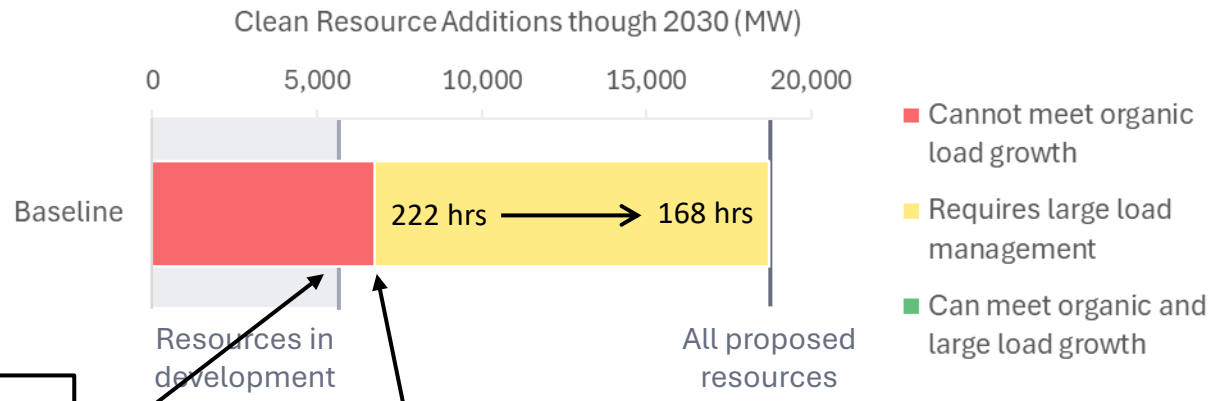
To compare across scenarios, we'll introduce a short-hand for the contributions of new clean resources toward meeting load growth and avoiding large load curtailments

Clean resource additions and large load management across the scenarios



1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

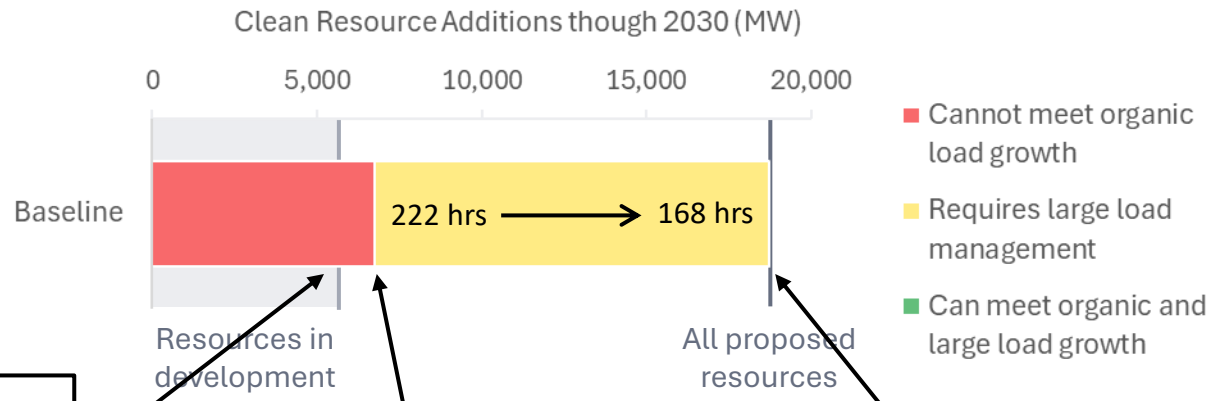
Clean resource additions and large load management across the scenarios



1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

2. Resources in development plus additional clean resources (6.7 GW total) <u>are</u> adequate to meet organic load growth, but require 222 hrs of large load curtailment

Clean resource additions and large load management across the scenarios

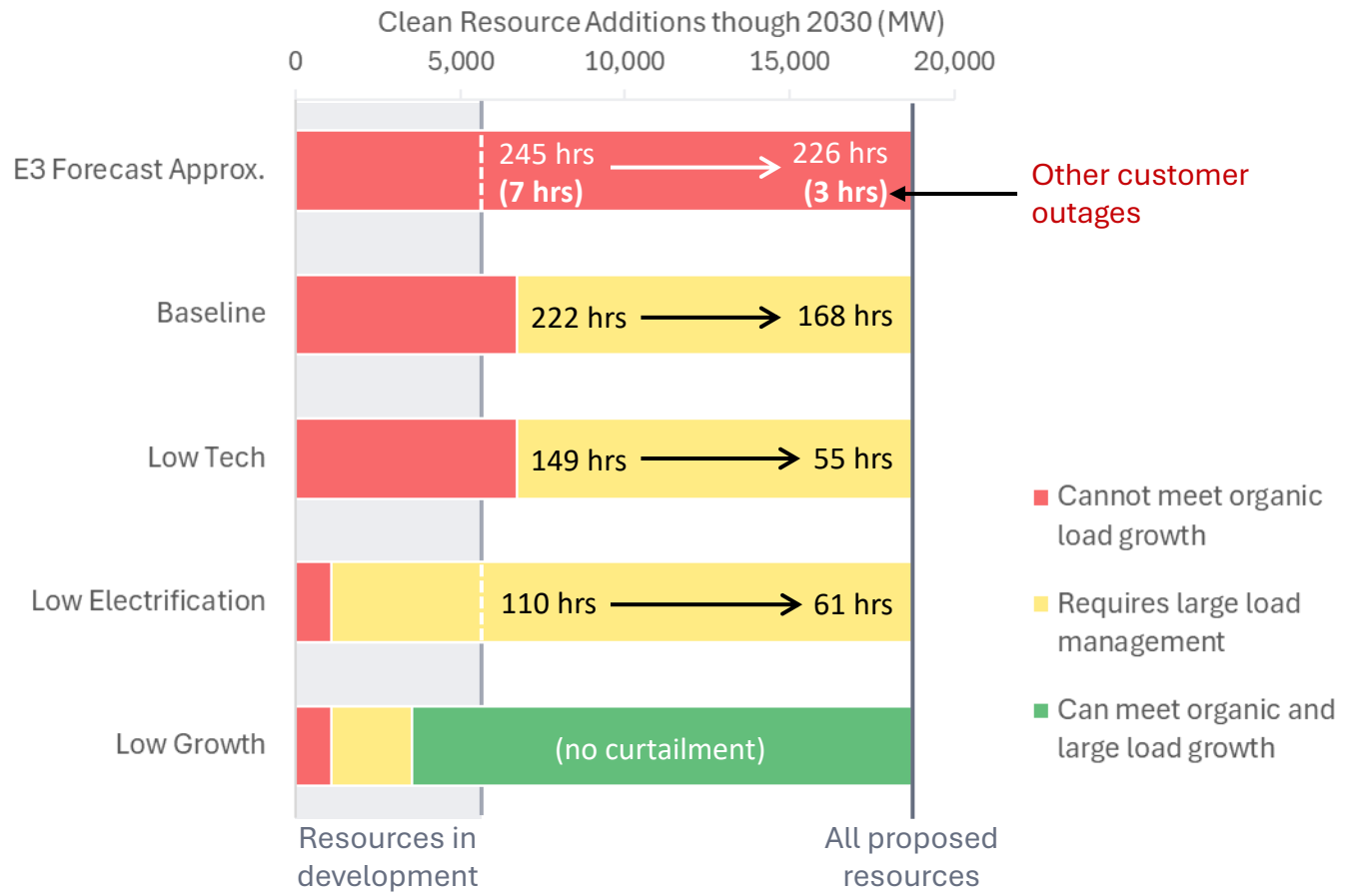


1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

2. Resources in development plus additional clean resources (6.7 GW total) <u>are</u> adequate to meet organic load growth, but require 222 hrs of large load curtailment

3. With all proposed clean resources (19 GW), large load curtailment persists (168 hrs)

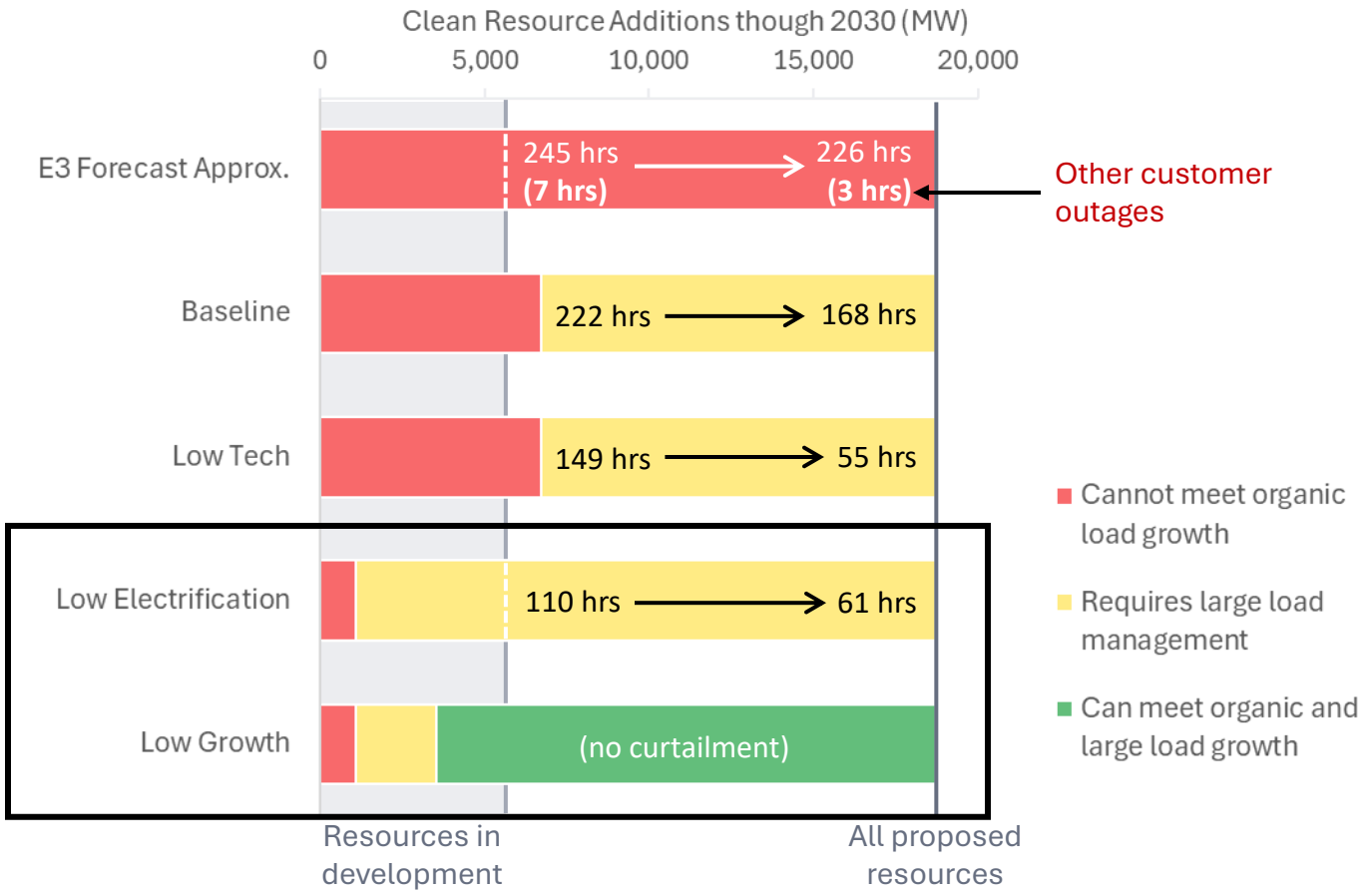
Clean resource additions and large load management across the scenarios



Clean resource additions and large load management across the scenarios

In scenarios without accelerated electrification (Low Electrification and Low Growth):

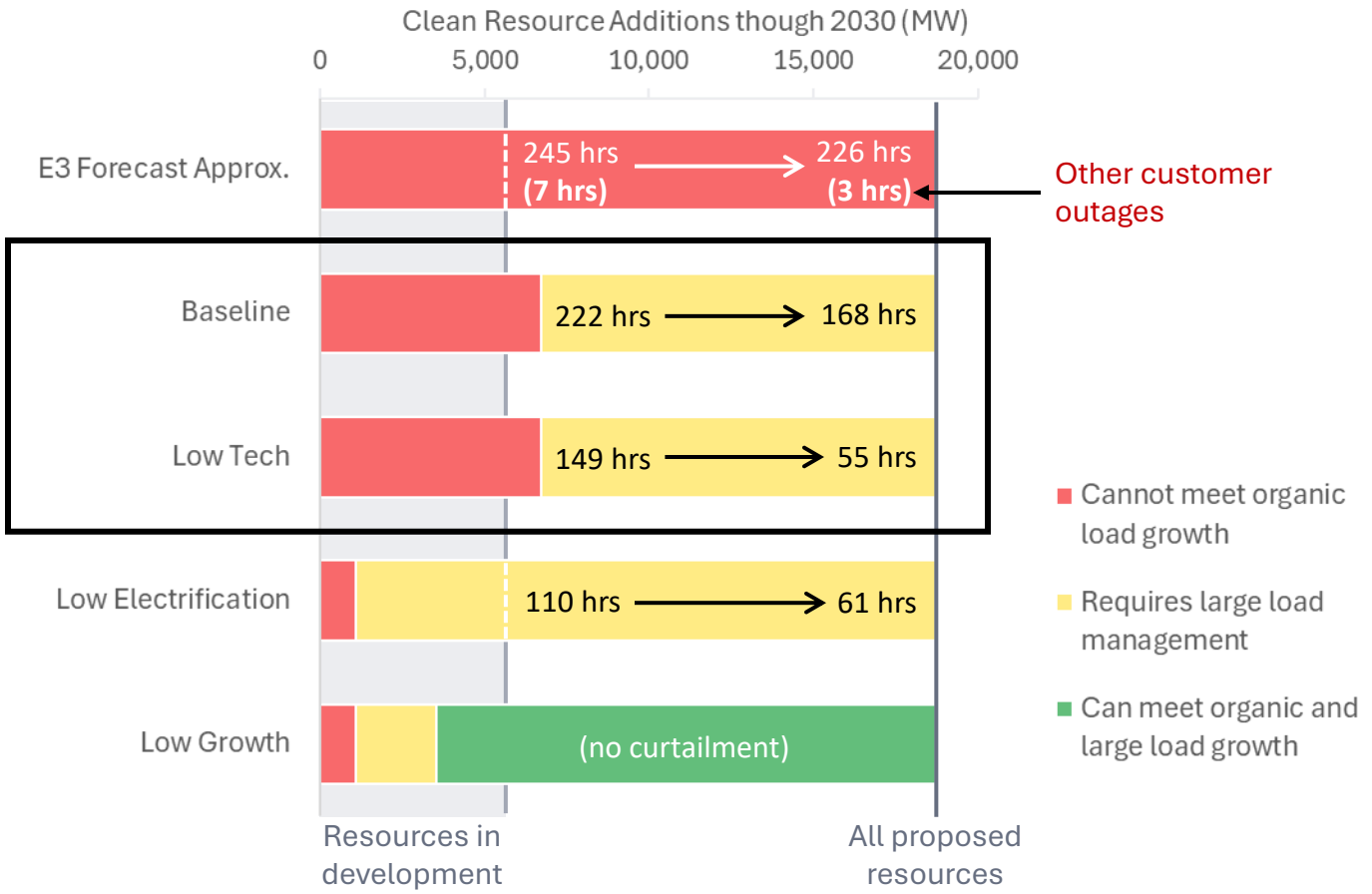
- Clean resources in development are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 0 hrs to 110 hrs)



Clean resource additions and large load management across the scenarios

In scenarios that project 1.4% annual organic load growth (Baseline and Low Tech):

- Clean resources in development plus a relatively small amount of incremental resources are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 55 hrs to 222 hrs)



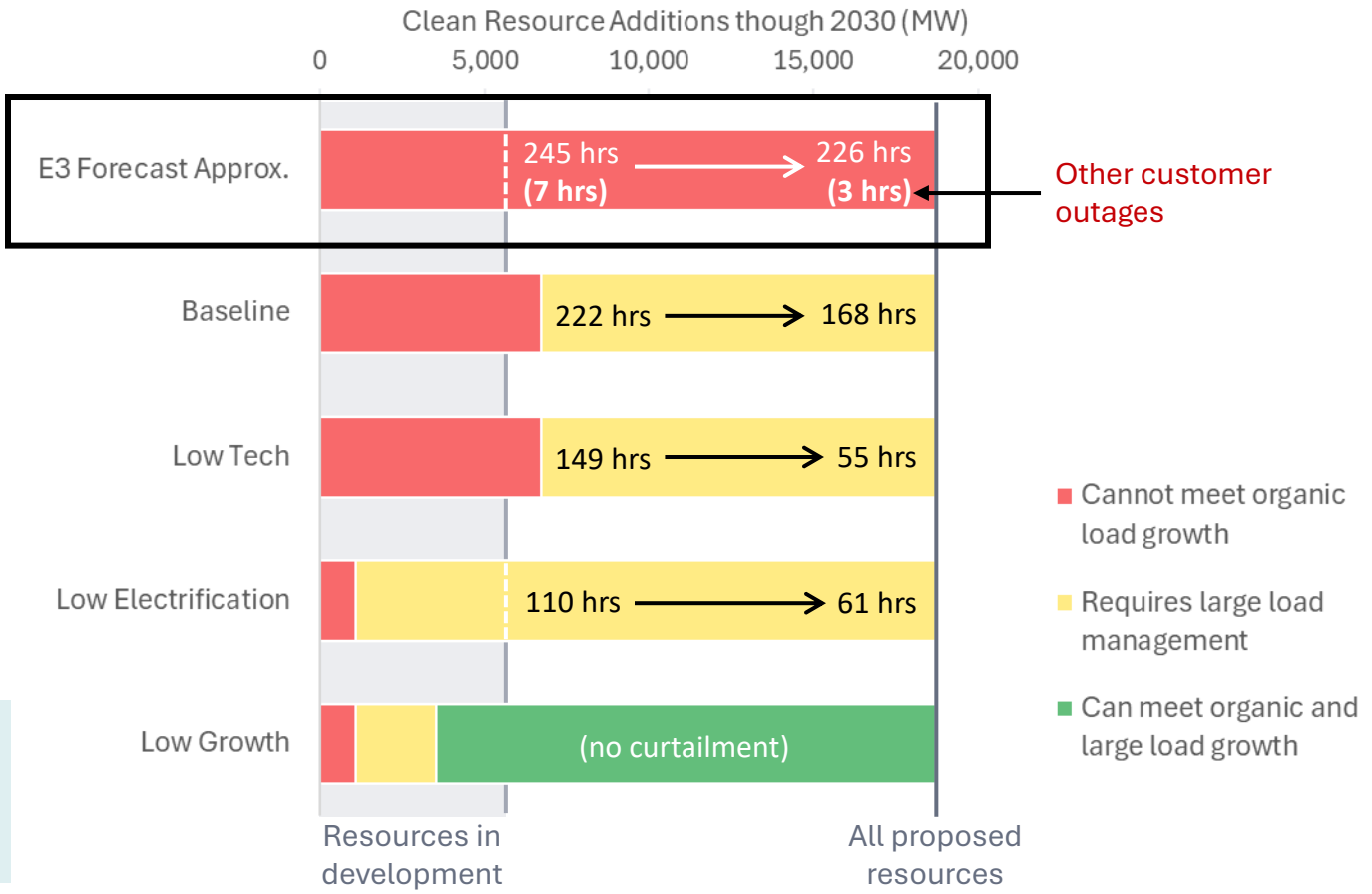
Clean resource additions and large load management across the scenarios

Under E3's load growth scenario, which includes more rapid electrification and relatively low data center demand, the region is in a real bind!

- Resource needs to meet organic growth exceed the quantity of proposed clean projects (19 GW)
- Large load curtailments exceed 100 hrs and other customers may experience rolling brown outs even with large load curtailments unless additional resources can come online
- New gas has been discussed as a solution to this challenge, but the gas system was constrained during the January 2024 event as well

Near-term opportunity:

➢ Study impacts of regional natural gas system constraints on regional electricity reliability

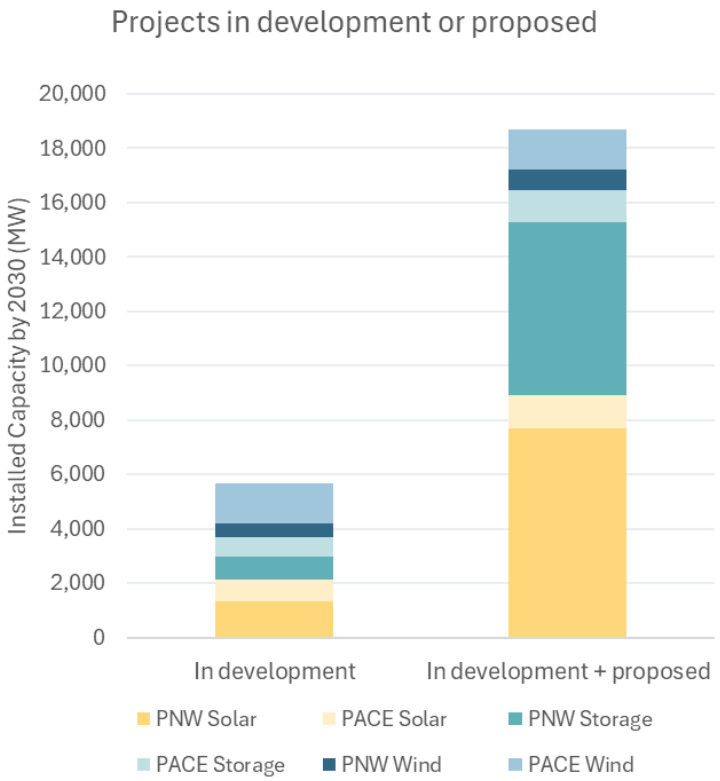


Winter portfolio ELCCs of new clean resources

Winter portfolio ELCCs estimated by calculating avoided perfect capacity during Jan 2024 weather/hydro event (not representative of summer contributions)

Baseline Load Scenario	Installed capacity (MW)	Avoided Perfect Capacity in Jan 2024 conditions (MW)	Approx. Winter Portfolio ELCC
All clean resources in development	5,666	1,875	33%
Additional clean resources pending approvals	13,009	2,473	19%
Total	18,675	4,348	23%

(Calculated before Centralia 2 coal-to-gas conversion and large load curtailments)

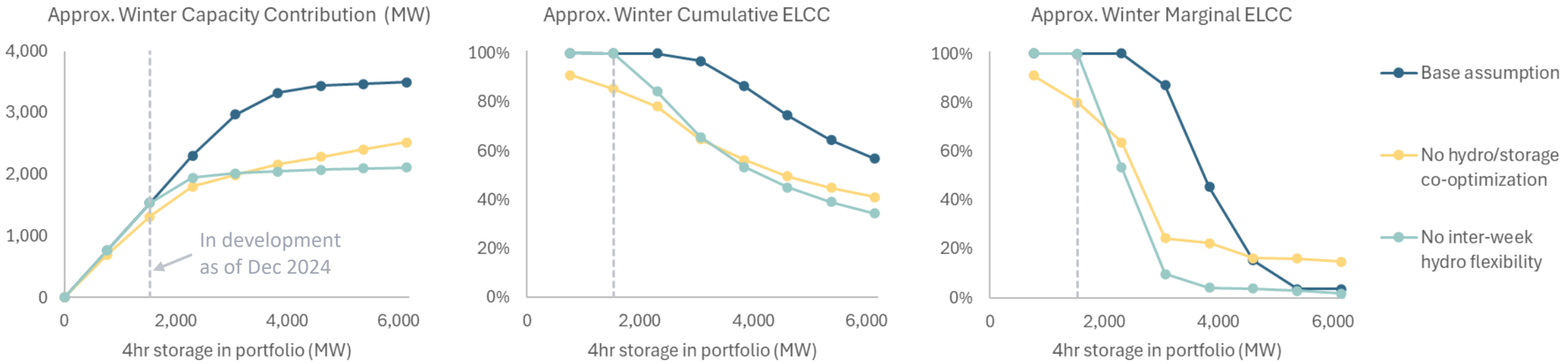


Near-term opportunity:

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities

Winter ELCCs of 4hr storage

- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
  1. Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
  2. Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch



Notes:

- Approximate winter capacity contributions were calculated as the reduction in capacity need during January 2024 weather & hydro conditions under the Baseline load scenario, with wind and solar that is in development and Centralia 2 coal-to-gas conversion
- These values do not account for contributions to resource adequacy in the summer and may not be applicable to individual utilities with unique constraints
- After conducting the analysis, we found that 332 MW of batteries came online in 2024, which were not included in the baseline dispatch simulations because they were not in January 2024 EIA 930 data. This analysis suggests these additional batteries would have reduced capacity needs in all simulations by about 330 MW.

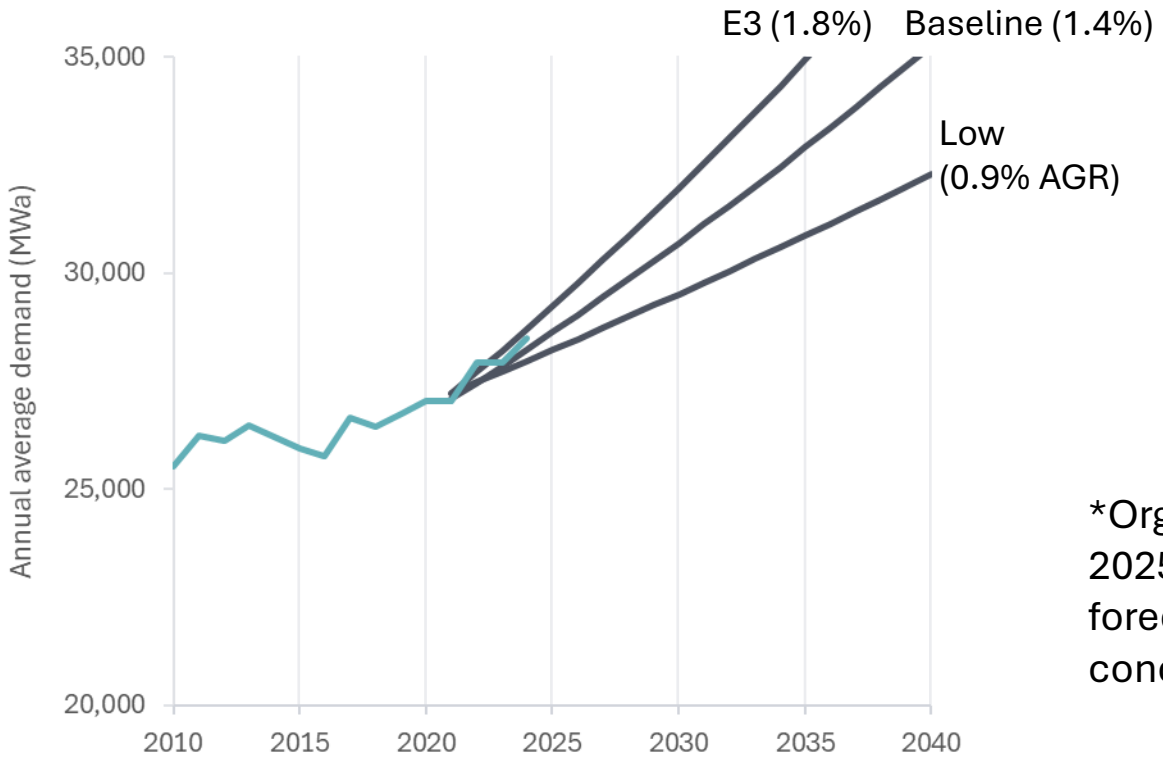


Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

The need for dispatchable or baseload solutions is not a question of if, but when

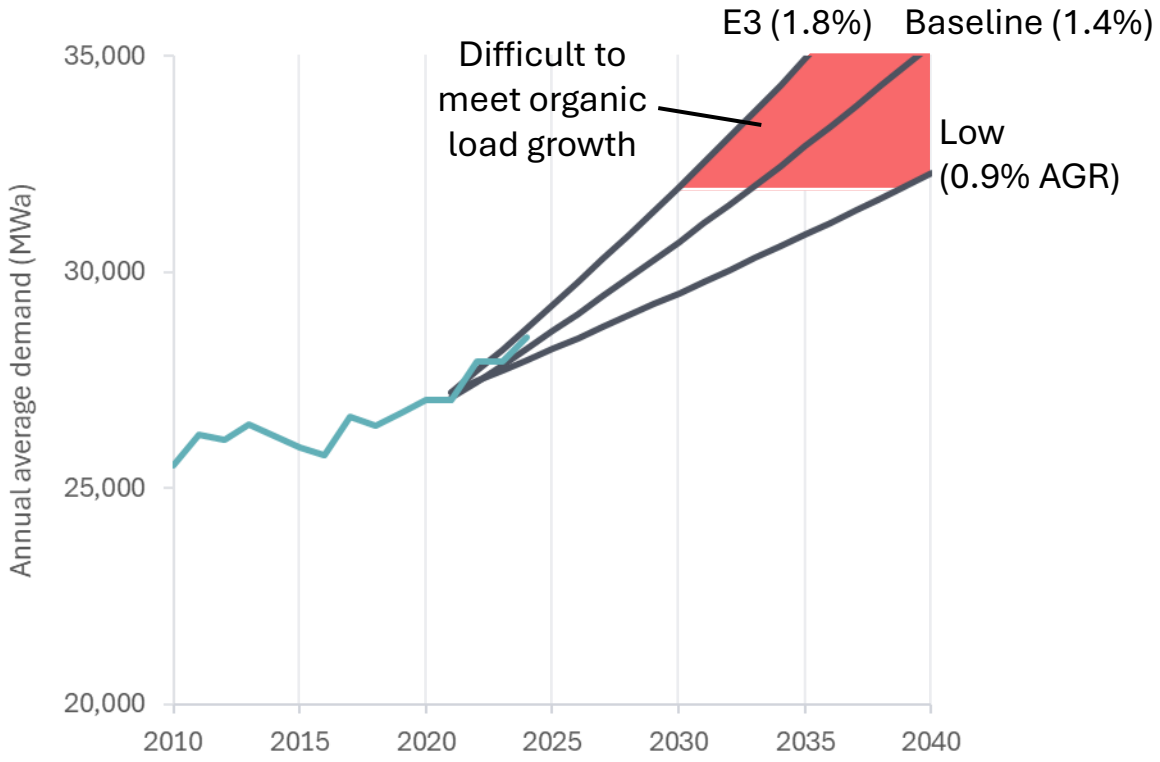
Extrapolated* organic load growth trajectories



*Organic load growth trajectories estimated by applying the 2025-2030 average annual organic load growth rate from each forecast to 2031-2040. This exercise is indicative and conceptual and may not align with actual load forecasts.

The need for dispatchable or baseload solutions is not a question of if, but when

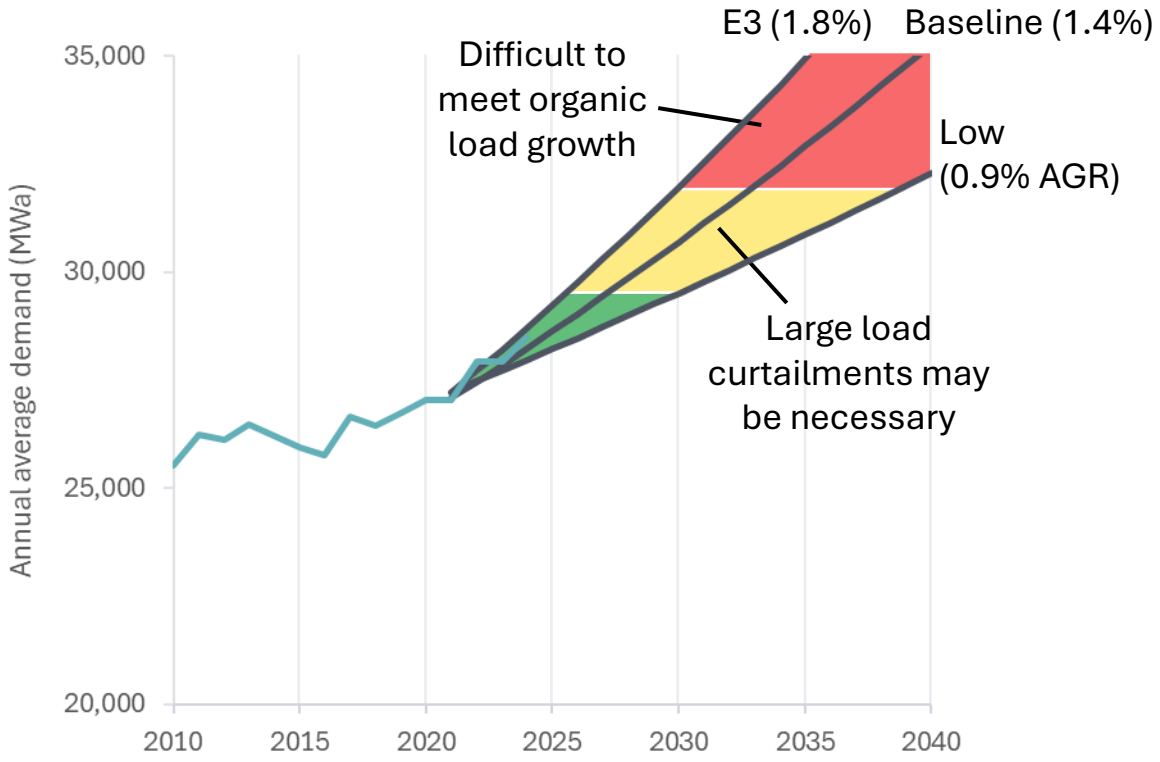
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
  - E3 Forecast: By 2030
  - Extrapolated Baseline Forecast: Roughly early 2030s
  - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

The need for dispatchable or baseload solutions is not a question of if, but when

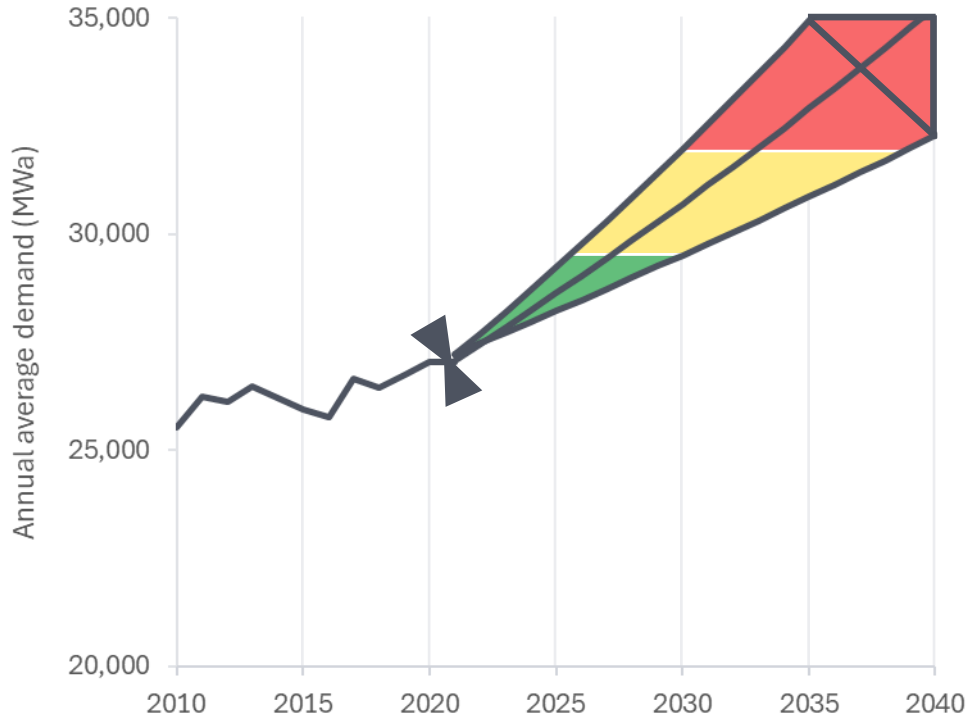
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
  - E3 Forecast: By 2030
  - Extrapolated Baseline Forecast: Roughly early 2030s
  - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution
- Large load flexibility requirements provide a crucial backstop across the scenarios

“A kite only flies when it’s tethered”

-Victor Robert Lee



We can’t control the wind (or the economy), but we have some tethers on the demand side that could buy the region some time

Near-term opportunities:

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)



Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Near-term opportunities identified to support regional RA

Policy

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages

Planning & Development

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)
- Prioritize transmission studies and upgrades that support increased South-to-North flows into the Pacific Northwest during the winter
- Schedule coal-to-gas conversion activities to minimize winter downtimes
- Study impacts of natural gas system constraints on electricity reliability

Operations

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest
- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits



Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

Thank you!

For more information, contact:

elaine@sylvan.energy

SYLVAN ENERGY ANALYTICS

EXHIBIT 107-2



SEPARATING FACT FROM FICTION IN DATA CENTER ELECTRICITY FORECASTS

A GUIDE FOR REGULATORS

MARCH 2026

KOOMEY ANALYTICS

GridLAB

Table of Contents

Preamble	**1**
Executive Summary	**2**
Historical parallels: Concern about electricity demand growth mirrors the early days of the Internet age	**3**
US and state-level electricity consumption growth in recent years	**5**
Aggregate electricity consumption of computing equipment	**8**
Historical compute data center electricity demand growth	**10**
US utilities project increasing demand	**12**
Lessons learned from historical load forecast analysis	**16**
The bottom line	**17**
Further reading	**18**
References cited	**20**
Appendix. Utilities and balancing authorities included in aggregate forecast tallies in Figure 6	**24**

Preamble

Authors

Jonathan Koomey[1]
Zachary Schmidt[1]
Priya Sreedharan[2]
Nikhil Kumar[2]
Taylor McNair[2]

1 *Koomey Analytics, Bay Area, California*
2 *GridLab, Berkeley, California*

US electric utilities are currently facing the challenge of integrating new loads into their power systems, including those from data centers. Given that recent forecasts project significant electricity load growth from this sector, industry leaders, utility planners, and regulatory bodies are intensely focused on understanding the implications of this expected growth.

To provide a clear, informed perspective, GridLab commissioned this white paper from Koomey Analytics. This report reviews recent load forecasts and industry announcements to rigorously assess the impact of new data center demand. Researchers Jonathan Koomey and Zachary Schmidt bring considerable historical experience to this review; they have observed and analyzed multiple distinct phases of the data center industry, including the rapid growth period of the early 2000s, the subsequent slowdowns through 2018, and the renewed, faster growth seen since.

In collaboration with the GridLab team, Koomey and Schmidt offer their expert perspective on current industry trends. They also provide key recommendations for regulators, policymakers, and other stakeholders who are responsible for accurately reviewing and planning for future data center load growth.

Executive Summary

Reports of "unprecedented" and "explosive" growth in electricity demand from data centers—facilities that host websites, store data, stream media, mine cryptocurrency, and train and deploy AI models—have focused public attention on these facilities as large-scale electricity consumers [1, 2, 3, 4, 5, 6, 7, 8]. The anticipated growth of the data center industry in coming years presents an opportunity for utility planners and regulators in regions with limited prior experience to deepen their understanding of these large-scale computing facilities.

Key takeaways from this white paper include:

- All computing (including compute data centers) was responsible for about 6% of electricity consumption globally in 2024, and while compute data centers appear to be growing, they're starting from a relatively small base (about 1.5% of the world's electricity in 2024). For the US, which has a higher concentration of data centers (and particularly AI facilities) total data center electricity use was about 4.4% in 2023, up from about 2% in 2020.
- For forecasts of data center electricity use, there is uncertainty on both the potential growth in service demand (the amount of compute we'll use) and the increase in efficiency of delivering that service demand. There are also open questions about potentially inflated or duplicate interconnection requests submitted by data center developers, which may lead to over-estimation of future electricity loads.
- Future projections of data center electricity demand are highly uncertain, so it's critical for regulators and utilities to examine carefully the assumptions driving forecasts of demand growth in the regions where these projections are emerging.
- Analysts, researchers, and policy makers should avoid the common tendency to overestimate the energy and environmental effects of information technology, which has been well documented for decades. They should also avoid citing or using "amazing factoids" until they've analyzed such claims independently.

This report also includes a list of follow-on resources and references for those who want to learn more.

HISTORICAL PARALLELS:

Concern about electricity demand growth mirrors the early days of the Internet age

Reports of "unprecedented" and "explosive" growth in electricity demand from data centers – facilities that house computing capacity needed to host websites, store data, stream media, mine crypto currency, and train artificial intelligence (AI) models — have appeared in several major US news outlets in recent months.

Here is a sampling of recent article headlines along these lines:

- **"A new surge in power use is threatening U.S. climate goals: A boom in data centers and factories is straining electric grids and propping up fossil fuels."** – *NY Times* [6]
- **"Amid explosive demand, America is running out of power."** – *Washington Post* [2]
- **"Internet data centers are fueling drive to old power source: Coal."** – *Washington Post* [5]
- **"US electric utilities brace for surge in power demand from data centers."** – *Reuters* [4]
- **"Booming AI demand threatens global electricity supply."** – *The Financial Times* [3]
- **"Our stressed-out power grids need help."** – *The Financial Times* [7]
- **"AI Power Consumption Exploding."** – *Semiconductor Engineering* [1]



These articles express two concerns: First, that rising energy demand from data centers could further burden the nation's aging power infrastructure; and second, that this new source of demand could jeopardize decarbonization trends in the US power sector.

Similar concerns emerge in recent reports by influential management consulting and investment advising firms such as McKinsey [9], Boston Consulting Group [10], Goldman Sachs [11], The Brattle Group [12], Brownridge [13], JP Morgan [14], Grid Strategies [15], and others. Together they have contributed to a sense that a power crisis could be looming and that energy requirements should be added to the long list of things that worry policy makers and citizens about AI more broadly.

This concern is not a new one. In the late 1990s and early 2000s, a similar set of concerns arose around the electricity used by computers and the Internet [16, 17, 18, 19, 20, 21]. Hyperbolic headlines like those above were commonplace, with consulting firms, trade organizations, politicians, and other respected authorities raising the alarm about ostensibly unprecedented electricity demand growth for computers.

This period coincided with the California electricity crisis, leading to erroneous claims that electricity used by computers was hampering grid reliability (it turned out to mostly be manipulation of markets by Enron and others [22], enabled by structural flaws in the design of California's power markets). The rapid expansion of the Internet fueled alarming projections, including estimates that data center peak power densities were approaching 300 watts per square foot and that information technology's total electricity use would soon balloon to 50% of US demand. These claims were overblown, as peer reviewed research showed at the time [17, 18, 19, 20, 21].

That furor created a rush to build new fiber optic capacity, driven by the mistaken belief that Internet data flows "double every 100 days" [23]. While this rate of increase held for about six months in 1995, data from before and after that six-month period suggest that data flows only doubled every year. The fiber industry used this erroneous factoid to argue that they couldn't possibly build enough fiber capacity to meet the demand, resulting in several high-profile corporate bankruptcies. By 2000, nearly 97% of the fiber network sat idle [17].

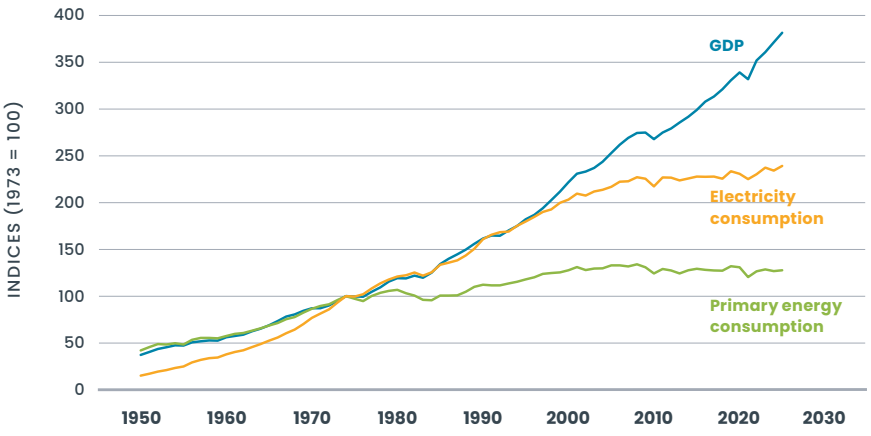
Just because it was hype last time doesn't mean it's hype this time. That's why it's worth looking carefully at the data and evidence to separate fact from fiction.

US and state-level electricity consumption growth in recent years

How seriously should decisionmakers take claims of "explosive" demand growth in the US in the years ahead? Let's begin with historical electricity consumption data from the US Energy Information Administration.

Changes in the composition and geographic distribution of different industries and economic activities have always influenced US electricity consumption, as have a host of other hard-to-predict factors, from technological developments and behavioral changes to short-term weather variations. Analysis of national US electricity demand shows that there is no evidence for explosive demand growth in recent years, although some states have seen demand growth. Consider **Figure 1**, which shows that US electricity demand growth has been modest in recent years in spite of significant increases in real GDP. Electricity use in 2023 was about the same as in 2018, while 2024 showed about 2.1% growth from 2023.

FIGURE 1. Historical US electricity use, primary energy use, and economic output (GDP) from 1950 to 2024

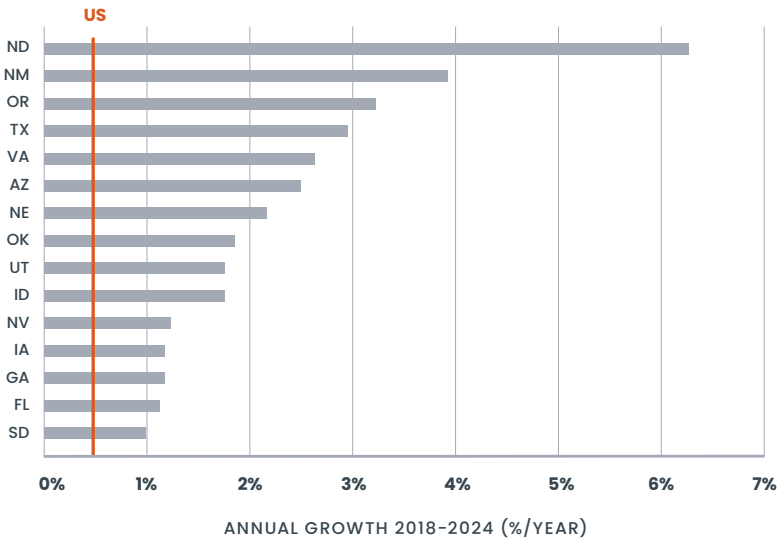


Source: www.eia.gov/opendata/

Average annual electricity sales growth rates varied significantly by state over the period 2018 to 2024, which is the period bracketing the recent pandemic (it also coincides with the latest period of growth in data center electricity use, see below). **Figure 2** shows those data for the top 15 states as ranked by average annual growth rate in sales from all sectors.

The two biggest states in this grouping in terms of absolute total sales were Texas and Virginia. Most of the other states on this list are smaller so higher growth rates are less surprising. The average annual growth rate for the US over this period was 0.5%/year, while for Texas it was almost 3%/year and for Virginia about 2.5%/year.

FIGURE 2. Historical annual growth/year in total electricity sales by state (2018 to 2024) for the top 15 states by growth rates

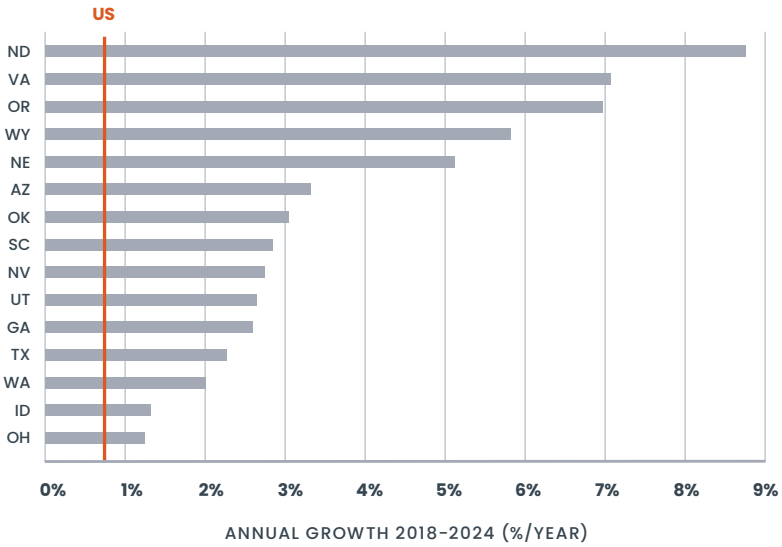


Source: www.eia.gov/opendata/

A similar picture emerges when considering commercial sector growth rates over that same period (2018 to 2024). Most data centers are situated in the commercial sector, though that varies by state. **Figure 3** shows the top 15 states ranked this time by commercial sector growth rates over the same period. The average annual growth rate for the US commercial sector over this period was 0.8%/year.

Virginia and Texas are still the two largest states in a set of fast-growing states, but when considering just the commercial sector, Virginia jumps up in the rankings to second place, with a growth rate of about 7%/year. Commercial sector growth in Texas was a little over 2%/year.

FIGURE 3. Historical annual growth/year in commercial sector electricity sales by state (2018 to 2024) for the top 15 states by commercial-sector growth rates



Source: www.eia.gov/opendata/

In sum, overall US electricity demand is growing, but the pace is moderate and growth is highly uneven, driven largely by specific regions and sectors such as data centers.

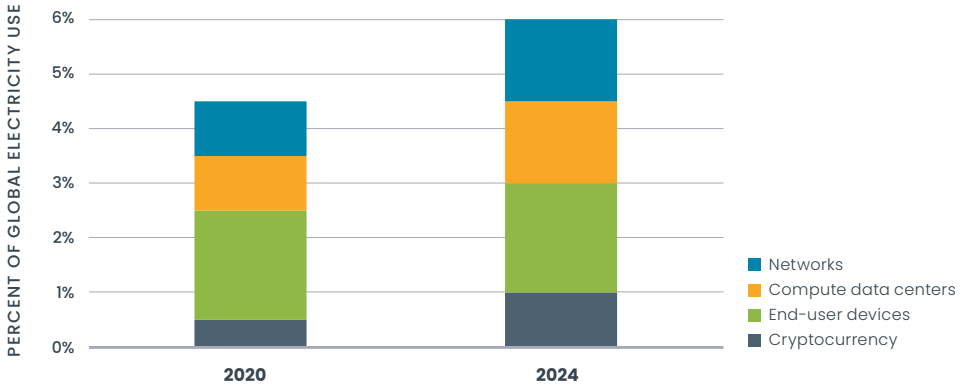
Aggregate electricity consumption of computing equipment

Centralized information technologies can be broadly divided into two categories: compute data centers, which run AI and other cloud services, and networks, which focus on transmitting and routing data. While these categories may overlap, their energy profiles can differ.

According to Malmodin et al. [24], compute data centers and networks each consumed about 1% of global electricity in 2020, with compute centers rising to 1.5% by 2024 according to the IEA [25]. End-user devices—such as laptops, desktops, smartphones, and printers—account for an additional 2% of global electricity use, a figure that has remained relatively steady. Cryptocurrency mining, dominated by Bitcoin, has fluctuated between 0.5% and 1%, with large year-to-year variations.

Figure 4 summarizes approximate fractions of global electricity use for these components in 2020 and 2024, based on the references cited in the caption. While compute data centers have grown, they are starting from a small base (1.5% of the total) so the absolute effect of this growth on total demand has been small so far. Total electricity consumption from all computing equipment and networks globally was about 6% of electricity use in 2024.

FIGURE 4. Approximate fractions of total global electricity use represented by different types of computing and network equipment in 2020 and 2024



Sources: Compute data centers and networks in 2020: Malmodin et al. [24]. Compute data centers in 2024: IEA [25]. networks in 2024 assumed to match compute data center total from IEA (1.5%). End-user devices in 2020 from Malmodin et al. [24], with percentage assumed constant to 2024. Cryptocurrency (Bitcoin) totals from Cambridge Bitcoin Energy Consumption Index (https://ccaf.io/cbnsi/cbeci) divided by electricity consumption totals from IEA [26].

Electricity use for compute data centers in the US is higher, because the US has expanded its data centers faster than have many other places. According to the Lawrence Berkeley National Laboratory's December 2024 report [27], US data centers used about 4.4% of US electricity in 2023, up from about 2% in 2018. Unfortunately, we don't have comparable data on end-user devices, cryptocurrency, and networks for the US as we do for the world.



Historical compute data center electricity demand growth

Most estimates of data centers' electricity use have been conducted at the global level, with some regional disaggregation. **Figure 5** summarizes the most important global estimates for data centers in recent years. These data only include compute data centers and exclude network providers and cryptocurrency. AI data centers are implicitly included within the category of compute data centers, and are sometimes explicitly identified, but have been relatively small until recently.

The peer reviewed estimates are those by Koomey [28], Masanet et al. [29], and Malmodin et al. [24]. These are shown as circles of different colors. From 2000-2005, data centers' electricity use doubled, then growth moderated between 2005-2010, and significantly slowed down in the decade after that. By 2018-2020, data centers used a little under 1% of the world's electricity.

The second group of data is from two organizations with some topic knowledge that produced nonpeer-reviewed estimates for 2021 from iMasons [30, 31] and for 2022 and 2024 from the International Energy Agency (IEA) [25, 26, 32]. iMasons is an industry group of the world's top data center designers, builders, and operators. IEA is a government-sponsored institution that tracks energy consumption and production trends globally and regionally. These data points are colored squares.

The iMasons estimate for 2021 is close to the 2020 data point from Malmodin et al. The IEA 2024a estimate for 2022 [32] is about 50% higher than Malmodin's 2020 data point. Unfortunately, the IEA report does not give enough information to determine how it arrived at this figure. It could indicate substantial recent growth, or it could be anomalous; nobody knows yet.

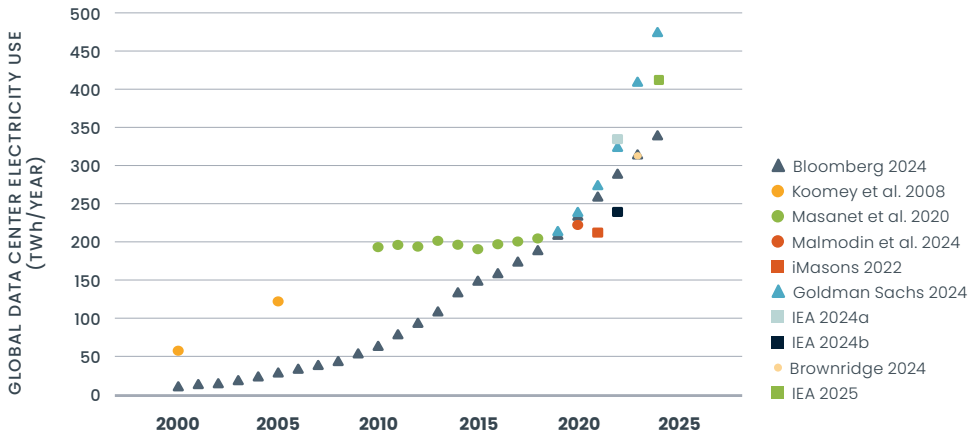
In October 2024, IEA released its World Energy Outlook [26], which gave a range of 240 to 340 TWh/year for total compute data center electricity use in 2022 (p. 186). This report is IEA 2024b in Figure 5. The top end of that range corresponds to the earlier IEA estimate, while the bottom end is closer to iMasons' and Malmodin's estimates. This report also does not give enough detail to determine how it arrived at these figures. The IEA 2025 report gives [25] a figure of 415 TWh/year for 2024, which is about 1.5% of global electricity use in that year. It is not clear exactly how this number was derived or how it relates to the range for 2022 given in one of the earlier IEA reports.

The other three estimates are from Bloomberg [33], Goldman Sachs [11], and Brownridge [13]. These data points are colored triangles. The three firms are analysis shops that are ostensibly credible, but some of these estimates should give one pause. The Bloomberg numbers pre-2020 are particularly concerning, given how low these estimates are compared with the peer-reviewed literature. The estimates for all three of these sources post-2020 are in the same ballpark as the first IEA number but given the lack of transparency for the data and methods for these estimates, it is impossible to know how accurate they are.

As time passes, more data will become available to determine whether the projected short-term growth post-2020 is a real phenomenon. Credible analysis always lags events in this space, which is often frustrating to policymakers.

In sum, the peer-reviewed literature on the electricity use of compute data centers points to a previous period of rapid growth (2000 to 2005) followed by slowing growth to 2010, and then much slower growth to 2018. **Growth clearly picked up after that point, but the data and the literature are unclear on whether that growth will continue or will moderate or continue in coming years.**

FIGURE 5. Estimates of global compute data center electricity use for historical years



Brownridge and Bloomberg numbers are almost exactly the same for 2023.

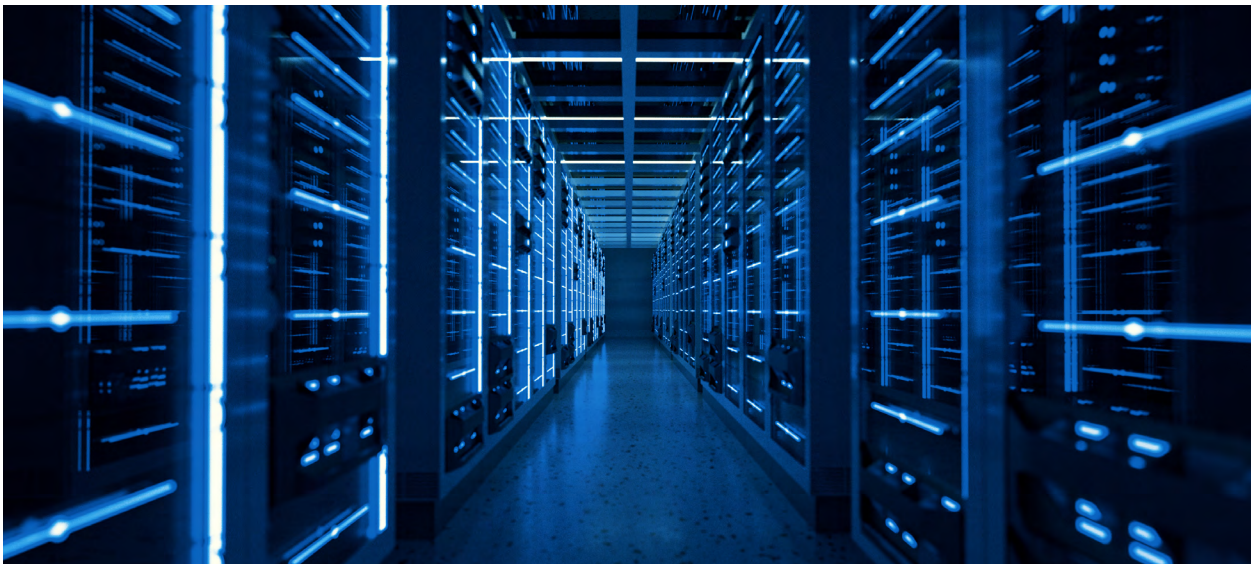
US utilities project increasing demand

While there's been relatively little recent growth in total US electricity demand, utility expectations of future demand growth have shifted since the pandemic.

To understand the relationship between historical electricity use trends and projections, we used data from the Federal Energy Regulatory Commission's Form 714, which compiles utility sector forecasts and historical generation every year for many utilities and most balancing authorities. Although no exhaustive database of forecasts covers the whole US, we compiled data for 14 utilities and balancing authorities representing about three-quarters of US generation in 2023 (see Appendix A for a complete list).

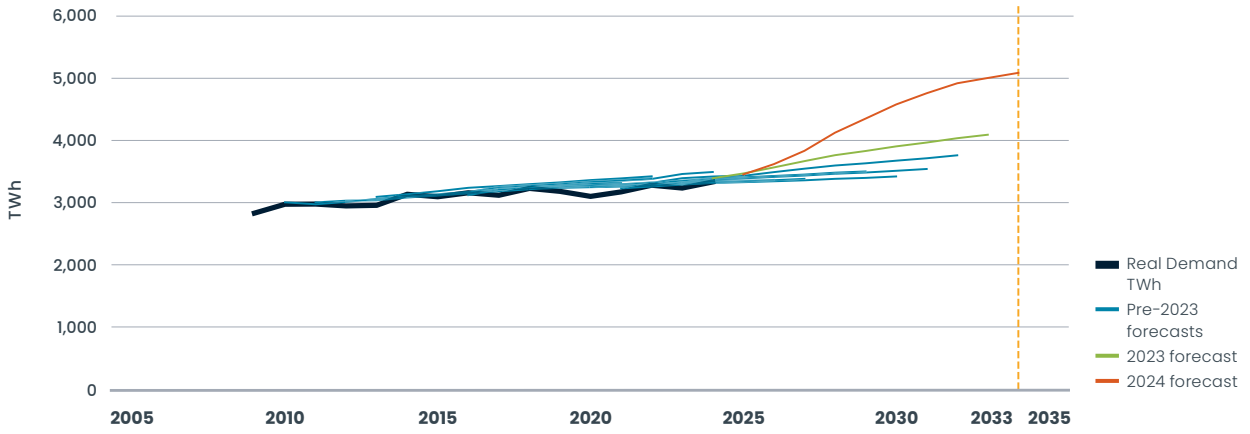
Figure 6 shows forecasts of total demand growth, including data centers (utilities in these balancing authorities often cite data centers as the main reason for growth [34]). The sum of 2023 forecasts for the year 2033 is several hundred TWh higher than the sum for 2022 forecasts in 2032 (the first blue line below the 2023 forecast), and the sum of the 2024 forecasts is more than 900 TWh above the 2023 forecasts for 2033. Clearly utilities expect more growth, but whether that growth will actually materialize is unclear.

This increase in projected growth is a local phenomenon. In our sample of 2024 forecasts for utilities and balancing authorities, only ERCOT (TX), PJM (Mid-Atlantic), California, and MISO



(Midwest) show significantly increased power projections from 2023 projections, and those account for 55%, 30%, 5.5%, and 4.8% of the 911 TWh/year increase, respectively (95% of the total growth). Understanding what's driving that projected growth would involve digging into the forecasts for these regions, a task that no one has yet done.

FIGURE 6. Aggregate electricity generation (actual and projected) for a large sample of US utilities



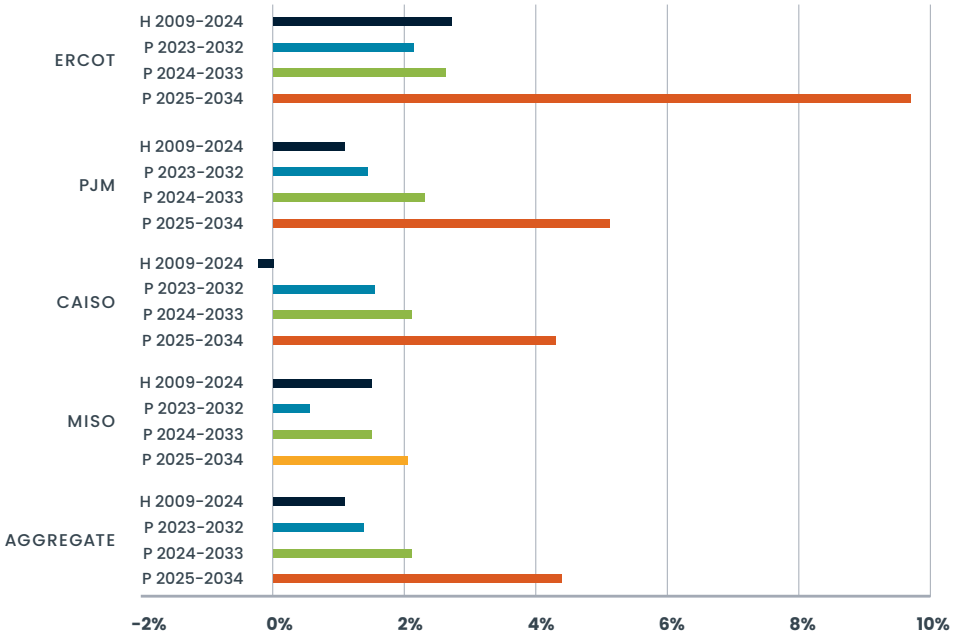
Source: FERC 714 data for utilities responsible for 75% of US net generation.

Figure 7 summarizes the projection data for the four regions showing the most growth plus the aggregate, using the same color coding as in Figure 3. Historical growth is in black, assessed from 2009 to 2024. The 2022 forecast is in blue, the 2023 forecast is in green, and the 2024 forecast is in red. It illustrates just how much the 2024 forecasts diverge from both historical trends and the two preceding forecasts.

For Texas (ERCOT), the latest projection is for more than 9%/year total annual growth, compared to almost 3%/year annual growth in the period 2018 to 2024 (see Figure 2 above). For PJM, which includes Virginia — home to "Data Center Alley" — as an important constituent part, projected growth is 4.5%/year, compared to 2.5%/year for Virginia from Figure 2. If average annual growth were measured relative to 2009 (as shown in Figure 7) that growth would be uniformly lower than what Figure 2 shows for the 2018 to 2024 period

Of course, this comparison doesn't mean the forecasters are wrong. The forecasts could be picking up real new growth. But the rapid increase suggested by the 2024 forecast is striking enough that it is surely worthy of more detailed study.

FIGURE 7. Annual growth rates in net generation, historical and projected for four balancing authorities and an aggregate representing ¾ of US generation



Source: FERC 714 data. Aggregate is a total for utilities responsible for 75% of US net generation.

There are reasons to be skeptical of these projections [35].

Data center developers consider multiple states as possible locations for data centers, and they query multiple utilities simultaneously for electricity rates and incentives prior to making a final selection. Therefore, counting data center project proposals to forecast load growth can result in overestimation of data centers likely to be built in a specific service territory. Only national or regional level tracking of these projects can give an accurate picture, but such tracking currently does not exist, at least in a publicly available form. Some double counting is likely.

In early 2025, the CEOs of Constellation Energy and Vistra Energy both raised concerns about forecasts overestimating data center growth.* James Burke, CEO of Vistra, is quoted as saying:

"We think these interconnect queues … may be overstated anywhere from three to five times what might actually materialize either in regulated markets or competitive markets."

* ieefa.org/resources/risk-ai-driven-overbuilt-infrastructure-real

On the other hand, compute data centers are not the only potential source of load growth. Crypto data centers, electric vehicles, electrification of heat in buildings, and electrification of industrial processes may all contribute to growth in the medium to longer term [25, 26].

The growth of two major factors will determine the impact of new computing applications on electricity demand:

- Service demand, as determined by the quantity of computations being performed
- Computing efficiency, as determined by the amount of energy required to perform each computation.

As segments of the computing industry grow rapidly, an additional third factor may come into play in the form of limits on industrial production capacity to supply AI chips and servers, to expand the infrastructure needed to build new data centers (such as backup power generators), and to modernize the electricity grid. These three drivers are interdependent, and their trajectory in coming years is difficult to predict [34].

Utility projections reflect the current conventional wisdom that demand for AI compute services is, if not infinite, at least so high that the technology industry will be able to use all the AI infrastructure they can build. That assertion is at best an untested hypothesis, not a certainty.

The conventional wisdom also assumes that training of AI models will continue to improve fastest by using scale, i.e., building the biggest models with the fastest computers and the largest datasets. That method has worked well in the recent past, with all efficiency gains plowed back into performance. It is an open question as to whether that will be the best or cheapest way to improve AI performance in the future, especially as new entrants like Deepseek and Z.ai demonstrate ways to produce comparable model results with one or two orders of magnitude less computing power [36].

In sum, data center electricity use forecasts contain inherent uncertainty on potential growth in service demand (the amount of compute we'll use) and growth in efficiency of delivering that service demand. There are also open questions about double counting of data center projects by different utilities [37].

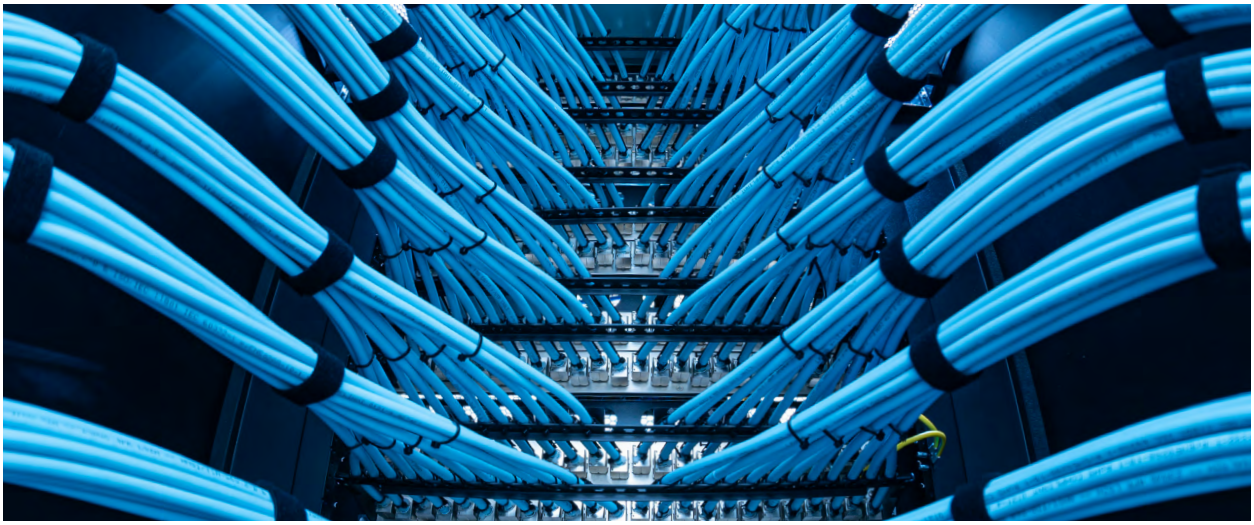
Nobody has any idea how much electricity data centers will use even a few years hence, so it's critical for regulators and utilities to carefully examine the assumptions driving forecasts of "explosive' demand growth in the regions where these projections are emerging.

Lessons learned from historical load forecast analysis

The early 2000s and the first Internet boom offer cautionary anecdotes and historical perspective on the fallacies of over forecasting electricity demand. While today's AI trends are surely unique, it is important to carefully vet industry claims and projected load growth forecasts. Regulators, policymakers, and industry stakeholders should remember:

- There is a well-documented tendency to exaggerate energy and environmental implications of data centers. Don't fall for it. [18] [38]
- Don't take any numbers at face value. Misinformation abounds, so every claim should be checked. Dig into the numbers! [21]
- Power utilization effectiveness (PUE) is a measure of infrastructure overhead energy use Water Usage Effectiveness (WUE) is a measure of onsite data center water use. Extrapolating PUE and WUE results from one facility to many dissimilar facilities is a recipe for disaster.
- PUEs and WUEs vary significantly over time, across seasons, and across facilities

In sum, it is prudent to avoid spreading or acting on "amazing factoids" about energy and environmental implications of data centers until such forecasts and facts have been carefully and independently evaluated.



The bottom line

Projections of massive electricity demand growth driven by AI are widely circulated, but the industry faces serious real-world constraints that point to a more modest and gradual outcome. The core issue is a disconnect between the tech sector's aggressive timelines and the slow, capital-intensive nature of infrastructure development. Utilities and grid operators must invest billions in new power plants, transmission lines, and substations, but these projects are subject to long permitting processes and interconnection delays that can stretch for years or even decades. Moreover, available generation capacity varies by region and is often limited, along with the inability to rapidly upgrade the transmission and distribution infrastructure needed to deliver power to specific locations.

Beyond infrastructure, financial and commercial uncertainties (including likely double counting of data center projects by different utilities) also dampen expectations for runaway load growth. The uncertainty raises the risk of overbuilding utility infrastructure, a concern already voiced by utilities and industry observers who note a growing number of canceled data center proposals or "phantom loads" that never materialize. In response, utilities are increasingly implementing tariffs and minimum-bill obligations that shift financial risk back to developers. Combined with the high capital costs of building new data centers and rising electricity prices, this financial caution acts as a natural brake. Companies must weigh the need to scale against limited capital and the risk of investing ahead of uncertain long-term demand.

The rate of growth will likely be determined less by technological desire and more by the slowest elements of the infrastructure supply chain, specifically the speed at which utilities can secure financing, gain permits, and physically build new generation and transmission. Additionally, increasing energy efficiency in new AI hardware and cooling systems and possibly lower growth in AI service demand may also help to offset the energy appetite of the next generation of data centers, pushing the eventual load growth down from the more aggressive end of current forecasts.

Further reading

IEA. 2025. *World Energy Outlook Special Report: Energy and AI.* Paris, France: International Energy Agency, Organization for Economic Cooperation and Development (OECD). April. [https://www.iea.org/reports/energy-and-ai]. The International Energy Agency creates authoritative reports on many topics, and this one is their latest on AI and energy. It is not possible to replicate all calculations in this report but it is still a useful reference and a great way to understand the global context.

Koomey, Jonathan, Zachary Schmidt, and Tanya Das. 2025. *Electricity Demand Growth and Data Centers: A Guide for the Perplexed.* Washington, DC: Bipartisan Policy Center. February. [https://bipartisanpolicy.org/report/electricity-demand-growth-and-data-centers/]. This white paper gives a readable high-level view of data center load growth in the US, which has mostly been local, but hasn't yet visibly affected national statistics on electricity consumption.

Lovins, Amory B. 2025. *Artificial Intelligence Meets Natural Stupidity: Managing the Risks.* May 10. [https://integrative-design-for-radical-energy-efficiency.stanford.edu/amory-lovins]. This essay, by one of the world's most renowned energy analysts, gives context for planners and regulators facing load growth uncertainties related to AI data centers.

Martin, Eliza, and Ari Peskoe. 2025. *Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power.* Cambridge, MA: Environmental & Energy Law Program, Harvard Law School. March. [https://eelp.law.harvard.edu/extracting-profits-from-the-public-how-utility-ratepayers-are-paying-for-big-techs-power/].

NERC. 2025. *Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper.* Atlanta, GA: North American Electric Reliability Council. July. [https://www.nerc.com/comm/RSTCReviewItems/3_Doc_White%20Paper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf]. NERC's focus is on power system reliability, and large loads have become a topic of increasing interest recently.

Shehabi, Arman, Sarah Josephine Smith, Alex Hubbard, Alexander Newkirk, Nuoa Lei, Md AbuBakar Siddik, Billie Holecek, Jonathan G Koomey, Eric R Masanet, and Dale A Sartor. 2024. *2024 United States Data Center Energy Usage Report.* Lawrence Berkeley National Laboratory. LBNL-2001637. December 19. [https://eta-publications.lbl.gov/publications/2024-lbnl-data-center-energy-usage-report]. This report is the third created by Berkeley Lab documenting data center electricity use in the US (the previous

two were in 2007 and 2016). It is well documented and the calculations are reproducible, which is not true of many reports on this topic. See also their center of expertise on data center energy efficiency: https://datacenters.lbl.gov.

Uptime Institute: https://uptimeinstitute.com. This organization, comprised of members who own and operate data centers, was founded at the beginning of the data center industry. It has historically focused on data center reliability, with some work on energy use over the years. They offer design services and collect industry statistics from their member organizations.

References cited

1. Bailey, Brian. 2022. "AI Power Consumption Exploding." In *Semiconductor Engineering*. [https://semiengineering.com/ai-power-consumption-exploding/]

2. Halper, Evan. 2024. "Amid explosive demand, America is running out of power." *Washington Post*. Washington, DC. March 7. [https://www.washingtonpost.com/business/2024/03/07/ai-data-centers-power/]

3. Hodgson, Camilla. 2024. "Booming AI demand threatens global electricity supply." *The Financial Times*. April 17. [https://www.ft.com/content/b7570359-f809-49ce-8cd5-9166d36a057b]

4. Kearney, Laila, Seher Dareen, and Deep Kaushik Vakil. 2024. "US electric utilities brace for surge in power demand from data centers." *Reuters*. April 10. [https://www.reuters.com/business/energy/us-electric-utilities-brace-surge-power-demand-data-centers-2024-04-10/]

5. Olivo, Antonio. 2024. "Internet data centers are fueling drive to old power source: Coal." *Washington Post*. Washington, DC. April 17. [https://www.washingtonpost.com/business/interactive/2024/data-centers-internet-power-source-coal/]

6. Plumer, Brad, and Nadja Popovich. 2024. "A new surge in power use is threatening US. climate goals: A boom in data centers and factories is straining electric grids and propping up fossil fuels." *New York Times*. New York, NY. March 14. [https://www.nytimes.com/interactive/2024/03/13/climate/electric-power-climate-change.html]

7. Schaake, Marietje. 2024. "Our stressed-out power grids need help." *Financial Times*. London, UK. March 13. p. 21.

8. Tarasov, Katie. 2024. "Generative AI requires massive amounts of power and water, and the aging U.S. grid can't handle the load." *CNBC*. July 28. [https://www.cnbc.com/2024/07/28/how-the-massive-power-draw-of-generative-ai-is-overtaxing-our-grid.html]

9. Bangalore, Srini, Arjita Bhan, Andrea Del Miglio, Pankaj Sachdeva, Vijay Sarma, Raman Sharma, and Bhargs Srivathsan. 2023. *Investing in the rising data center economy*. San Francisco Bay Area, CA: McKinsey & Company, Technology, Media, & Telecommunications Practice. January. [https://www.mckinsey.com/~/media/mckinsey/industries/technology%20media%20and%20telecommunications/high%20tech/our%20insights/investing%20in%20

the%20rising%20data%20center%20economy/investing-in-the-rising-data-center-economy_final.pdf]

10. Lee, Vivian. 2023. *The Impact of GenAI on Electricity: How GenAI is Fueling the Data Center Boom in the U.S.* Boston, MA: Boston Consulting Group (BCG). September 13. [https://www.linkedin.com/pulse/impact-genai-electricity-how-fueling-data-center-boom-vivian-lee/]

11. Davenport, Carly, Brian Singer, Neil Mehta, Brian Lee, and John Mackay. 2024. *Generational Growth: AI, data centers and the coming US power demand surge*. New York, NY: Goldman Sachs Equity Research. April 28. [https://www.goldmansachs.com/intelligence/pages/gs-research/generational-growth-ai-data-centers-and-the-coming-us-power-surge/report.pdf]

12. Tsuchida, T. Bruce, Long Lam, Peter Fox-Penner, Akhilesh Ramakrishnan, Sylvia Tang, Adam Bigelow, and Ethan Snyder. 2024. *Electricity demand growth and forecasting in a time of change*. San Francisco, CA: The Brattle Group. May. [https://www.brattle.com/insights-events/publications/electricity-demand-growth-and-forecasting-in-a-time-of-change/]

13. Brown, Jeff. 2024. *Data Center Electricity Consumption is About to Quadruple*. Dover, DE: Brownridge Research. June 3. [https://www.brownridge.com/data-center-electricity-consumption-is-about-to-quadruple/]

14. Cembalest, Michael. 2024. *Electravision: Eye on the market, 14th annual energy paper*. New York, NY: JP Morgan Asset & Wealth Management. [https://privatebank.jpmorgan.com/nam/en/insights/latest-and-featured/eotm/annual-energy-paper]

15. Wilson, John D., and Zach Zimmerman. 2023. *The era of flat power demand is over*. Washington, DC: Grid Strategies, sponsored by the Clean Grid Initiative. December. [https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf]

16. Huber, Peter, and Mark P. Mills. 1999. "Dig more coal—the PCs are coming." In *Forbes*. May 31. pp. 70-72. [http://www.forbes.com/global/1999/0531/0211100a.html]

17. Koomey, Jonathan. 2003. "Sorry, Wrong Number: Separating Fact from Fiction in the Information Age." In *IEEE Spectrum*. June. pp. 11-12. [http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=1203076&tag=1]

18. Koomey, Jonathan, Chris Calwell, Skip Laitner, Jane Thornton, Richard E. Brown, Joe Eto, Carrie Webber, and Cathy Cullicott. 2002. "Sorry, wrong number: The use and misuse of numerical facts in analysis and media reporting of energy issues." In *Annual Review of Energy and the Environment 2002*. Edited by R. H. Socolow, D. Anderson and J. Harte. Palo Alto, CA: Annual Reviews, Inc. (also LBNL-50499). pp. 119-158. [http://www.annualreviews.org/doi/abs/10.1146/annurev.energy.27.122001.083458]

19. Kawamoto, Kaoru, Jonathan Koomey, Bruce Nordman, Richard E. Brown, Maryann Piette,

Michael Ting, and Alan Meier. 2002. "Electricity Used by Office Equipment and Network Equipment in the U.S." *Energy–The International Journal (also LBNL-45917)*. vol. 27, no. 3. March. pp. 255-269. [http://www.sciencedirect.com/science/article/pii/S0360544201000846]

20. Koomey, Jonathan, Kaoru Kawamoto, Bruce Nordman, Mary Ann Piette, and Richard E. Brown. 1999. *Initial comments on 'The Internet Begins with Coal'*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-44698. December 9. [https://eta.lbl.gov/publications/initial-comments-internet-begins-coal]

21. Koomey, Jonathan. 2017. *Turning Numbers into Knowledge: Mastering the Art of Problem Solving*. 3rd ed. El Dorado Hills, CA: Analytics Press. [http://amzn.to/2wY1m7x]

22. Peterson, Jonathan, and Nancy Rivera Brooks. 2003. "California Report Widens Blame in Energy Plot." Los Angeles, CA. March 3. [https://www.latimes.com/archives/la-xpm-2003-mar-03-fi-ferc3-story.html]

23. Coffman, K. G., and Andrew M. Odlyzko. 1998. "The size and growth rate of the Internet." *First Monday*. [https://firstmonday.org/ojs/index.php/fm/article/view/620/541]

24. Malmodin, Jens, Nina Lövehagen, Pernilla Bergmark, and Dag Lundén. 2024. "ICT sector electricity consumption and greenhouse gas emissions – 2020 outcome." *Telecommunications Policy*. vol. 48, no. 3. 2024/04/01/. pp. 102701. [https://www.sciencedirect.com/science/article/pii/S0308596123002124]

25. IEA. 2025. *World Energy Outlook Special Report: Energy and AI*. Paris, France: International Energy Agency, Organization for Economic Cooperation and Development (OECD). April. [https://www.iea.org/reports/energy-and-ai]

26. IEA. 2024. *World Energy Outlook 2024*. Paris, France: International Energy Agency, Organization for Economic Cooperation and Development (OECD). October. [https://www.iea.org/reports/world-energy-outlook-2024]

27. Shehabi, Arman, Sarah Josephine Smith, Alex Hubbard, Alexander Newkirk, Nuoa Lei, Md AbuBakar Siddik, Billie Holecek, Jonathan G Koomey, Eric R Masanet, and Dale A Sartor. 2024. *2024 United States Data Center Energy Usage Report*. Lawrence Berkeley National Laboratory. LBNL-2001637. December 19. [https://eta-publications.lbl.gov/publications/2024-lbnl-data-center-energy-usage-report]

28. Koomey, Jonathan. 2008. "Worldwide electricity used in data centers." *Environmental Research Letters*. vol. 3, no. 034008. September 23. [http://stacks.iop.org/1748-9326/3/034008]

29. Masanet, Eric, Arman Shehabi, Nuoa Lei, Sarah Smith, and Jonathan Koomey. 2020. "Recalibrating global data center energy-use estimates." *Science*. vol. 367, no. 6481. Feb 28. pp. 984. [http://science.sciencemag.org/content/367/6481/984.abstract]

30. Nelson, Dean. 2022. "Defining The Digital Infrastructure Industry." In *Interglobix Magazine*. February 10. [https://www.interglobixmagazine.com/defining-the-digital-infrastructure-industry/]

31. iMasons. 2024. *State of the digital infrastructure industry: Annual report*. Infrastructure Masons. [https://imasons.org/blog/state-of-the-digital-infrastructure-industry-report-2024/]

32. IEA. 2024. *Electricity 2024: Analysis and forecast to 2026*. Paris, France: International Energy Agency. January. [https://www.iea.org/reports/electricity-2024]

33. Bloomberg. 2024. "AI is already wreaking havoc on global power systems." June 21. [https://www.bloomberg.com/graphics/2024-ai-data-centers-power-grids/]

34. Koomey, Jonathan, Zachary Schmidt, and Tanya Das. 2025. *Electricity Demand Growth and Data Centers: A Guide for the Perplexed*. Washington, DC: Bipartisan Policy Center. February. [https://bipartisanpolicy.org/report/electricity-demand-growth-and-data-centers/]

35. Lovins, Amory B. 2025. *Artificial Intelligence Meets Natural Stupidity: Managing the Risks*. May 10. [https://integrative-design-for-radical-energy-efficiency.stanford.edu/amory-lovins]

36. Liu, Aixin, and et al. 2025. *DeepSeek-V3 Technical Report*. Arxiv. [https://arxiv.org/abs/2412.19437]

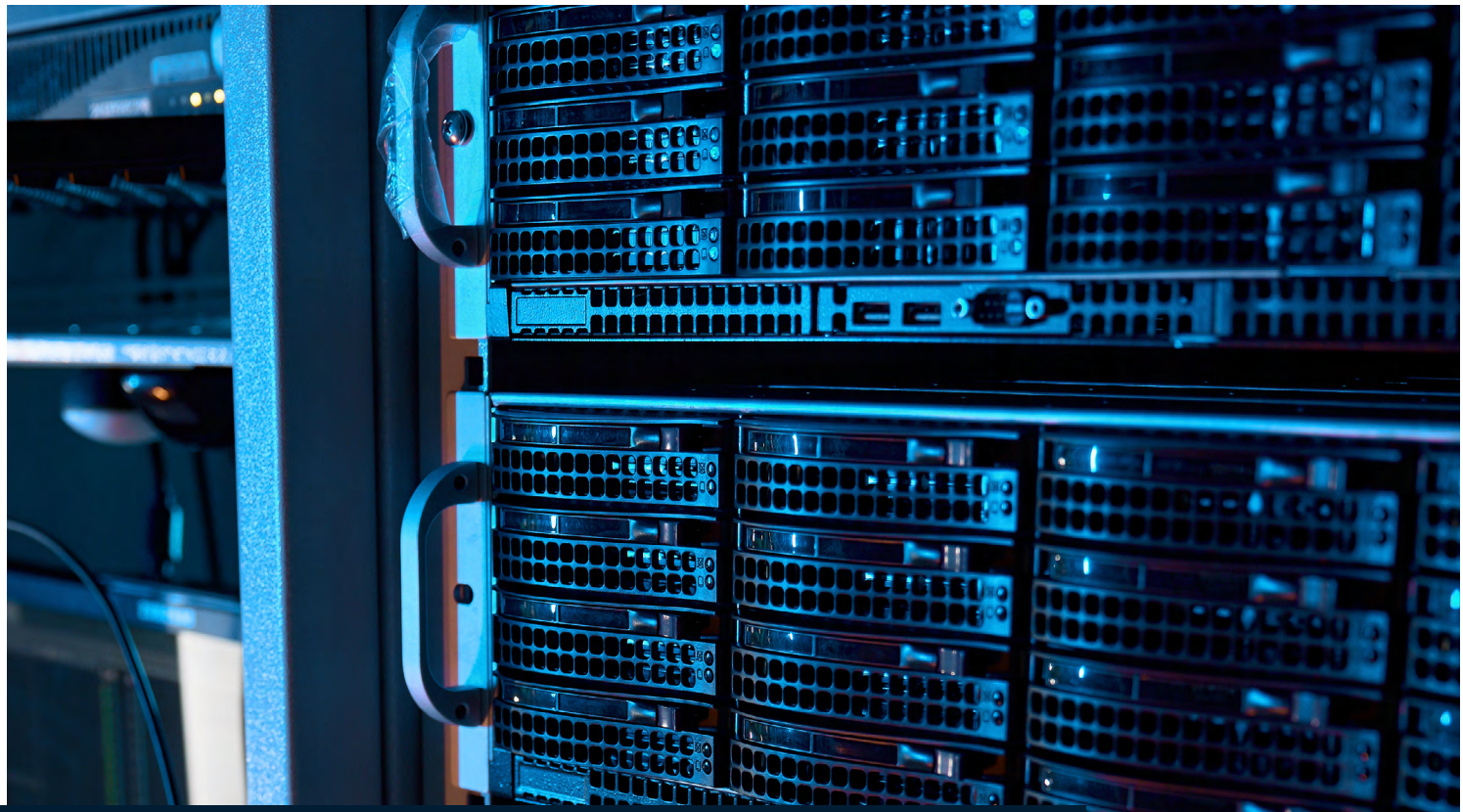
37. Wilson, John D., Sophie Meyer, Zach Zimmerman, and Rob Gramlich. 2025. *Power demand forecasts revised up for third year running, led by data centers.* Washington, DC: Grid Strategies, sponsored by the Connected Grid Initiative. November. [https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf]

38. Koomey, Jonathan, and Eric Masanet. 2021. "Does not compute: Avoiding pitfalls assessing the Internet's energy and carbon impacts." Joule. vol. 5, no. 7. June 24. pp. 1625-1628. [https://www.sciencedirect.com/science/article/abs/pii/S2542435121002117]

APPENDIX

Utilities and balancing authorities included in aggregate forecast tallies in Figure 6

Arizona Public Service Company
Bonneville Power Administration
California Independent System Operator
Duke Energy Carolinas
ERCOT
Florida Power & Light Company
Georgia Power
ISO New England
MISO
NYISO
PJM
Puget Sound Energy
Southwest Power Pool
Tennessee Valley Authority



KOOMEY ANALYTICS

Koomey Analytics creates quantitative analyses, data, training classes, books, and peer-reviewed publications for academic, non-profit, and corporate clients who really want to get the numbers right. Primary research topics include data centers, trends in information technology, climate solutions, scenario analysis, and critical thinking skills.

koomey.com

GridLAB

GridLab is an innovative non-profit that provides technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future.

gridlab.org

hello@gridlab.org



EXHIBIT 107-3

Proposed Options for Bilateral Integration of Generation Portfolios and Load (BIGPAL)

PREPARED BY

ANDREW LEVITT

JOHANNES PFEIFENBERGER

ANIRUDDH MOHAN

SERENA PATEL

PREPARED FOR

eolian

SEPTEMBER 26, 2025

Brattle



Proposed Options for Bilateral Integration of Generation Portfolios and Load (BIGPAL)

PJM urgently needs solutions to bring online new capacity quickly to meet large load growth

- PJM expects ~23 GW of new load by 2030, but only ~12 GW UCAP of new total capacity => this contributes to **potential reliability shortfall** >10 GW, also creating affordability concerns

Brattle-Eolian BIGPAL proposed options:

Operationally-linked capacity portfolio framework to allow large loads to cover their capacity needs with adjacent supply, with large load flexibility (including backup generation) as a backstop allowing for dependable emergency operations and commercially flexible allocation of ELCC, performance, and counterparty risk

90-day interconnection study for new generation operationally-linked w/ new adjacent load (and facilitate linked studies for load integration)

The benefits of this approach are:

- Accelerated connection of new PJM supply addressing capacity supply shock and reliability shortfall
- Flexible contracting allows adjacent but commercially distinct entities to self-supply resource adequacy, transferring risks (ELCC, performance, counterparty) from PJM to the contracting parties (w/ flexible allocation among them)
- Similar to established tariff mechanisms
- No mandates on load curtailment or use of specific resources; technology agnostic solutions
- Makes possible accelerated load interconnection by pairing new supply with new load

BIGPAL Design Sketch

Eligibility

- Available to **new large loads**
- Any type of **new generation** (including storage, gas, nuclear…) that is **front-of-meter** and located electrically adjacent to new load
- "Adjacent" means electrically equivalent (e.g., same substation; can be different busses, different parcels)

Market Concept

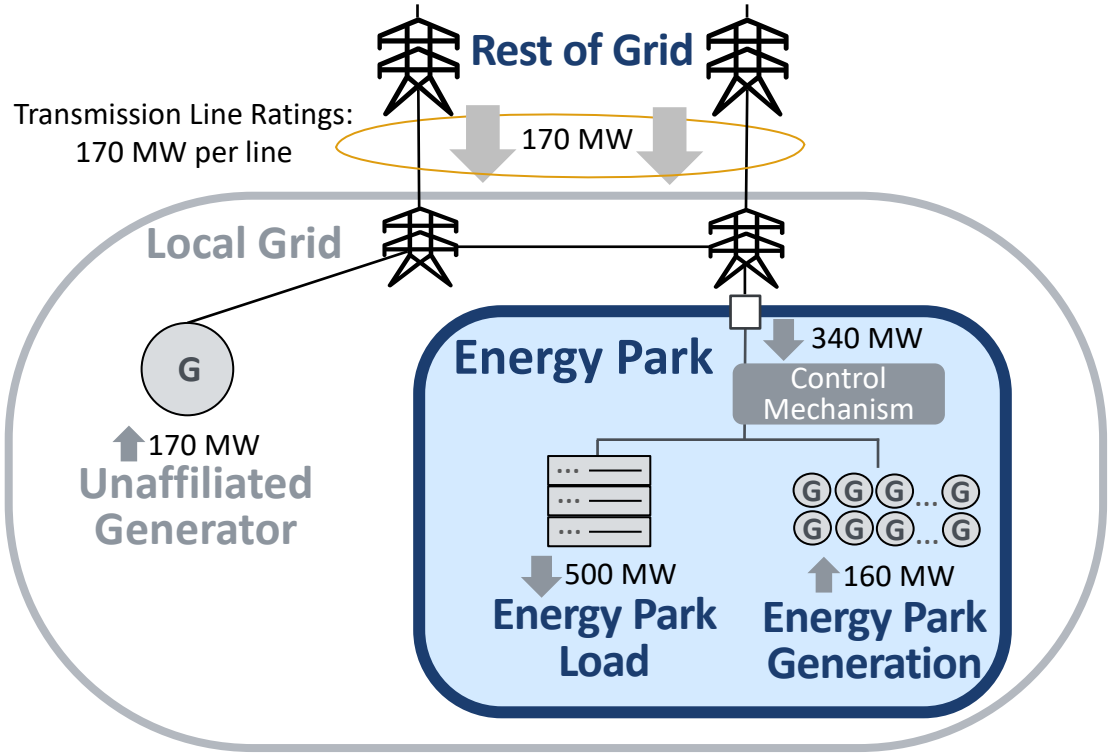
- Bilateral capacity contracts between large loads and adjacent resources with front-of-meter market participation
- Net capacity market impact of BIGPAL is 0 MW by definition (i.e, value of curtailment-backed resources meets capacity need of the large load)
- Performance obligation is 0 MW net withdrawals from the portfolio + load during Performance Assessment Interval or other grid emergency (i.e., backstop of load curtailment if the adjacent portfolio of capacity resources fails to perform)

- Allows parties to assume performance risk through contractual means, instead of PJM designations
- No ELCC accreditation (assumes dependable net performance of resource portfolio and load)
- Large load curtailment/flexibility is *backstop only*, not called upon (by PJM) unless contracted capacity resources are short during PAI

Fast Interconnection for New Supply: Adjacency w/ New Load Avoids Transmission Upgrades

- **We propose a 90-day interconnection process for new generation linked with large load in a BIGPAL**
- It is intuitive that connecting 500 MW load **electrically adjacent** to 550 MW generation (similar to an Energy Park, as shown at right) would cause minimal grid impact in intact grid conditions
  - Net flows on to the grid are lower when a new load is consuming there
  - Self balancing effect of load and generation results in limited system impacts
- Transmission upgrades are often driven by impacts under contingencies (N-1 and N-1-1)—resources adjacent to new large load also tends to avoid those upgrades
- SPP takes advantage of this in their HILLGA proposal for 90-day interconnection of co-located generation and large load

Network Model for Impact Studies: Intact Grid



SPP, 2025, High Impact Large Load Integration

Brattle, 2025, Accelerating the Integration of New Co-located Generation and Loads

BIGPAL Example: Adjacent Battery + Large Load

Large Load: 100 MW	Battery: 100 MW ICAP 50 MW UCAP

Capacity market impact = zero net MW

Under Brattle-Eolian BIGPAL Proposed Options:

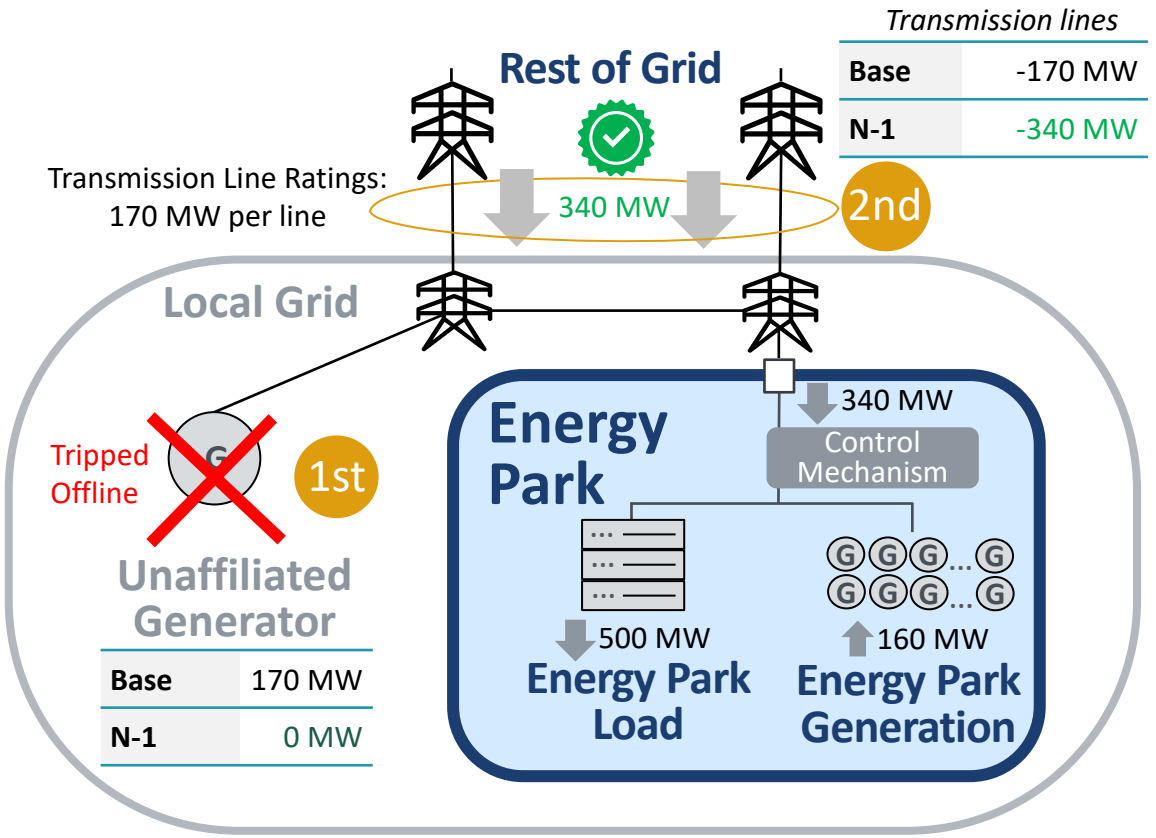
- During PAI event if battery supplies 100 MW, **large load <u>not subject</u> to curtailment**
- **<u>Allows parties to assume performance risk:</u>** ability of adjacent load to match generation may not be a function of system-wide resource accreditation
- If storage is exhausted before the end of the PAI event or other grid emergency, large load provides **<u>backstop load reduction</u>** of 100 MW (by leveraging on-site flexibility or back-up supply) until end of emergency (but likely before PJM would end dispatch of demand response resources)

BIGPAL achieves PJM goals:

1. **Reliability**: PJM gets assurance of **net-zero withdrawals** during PAI (or other grid emergencies)
2. **Affordability**: Zero net MW **capacity market impact** (ensured through direct operation links/controls) isolates the capacity market from any effect from the BIGPAL participants

Example: N-1 Contingency Study for Adjacent Load + Generation

- In the N-1 case for reliability studies, an unaffiliated generator trips offline, stressing the grid near the new large load
- Because the adjacent generation is modeled in the same case as the new load, the increased flow over the transmission network does not cause overloads in this stress test N-1 case
- In this example, the system can return to N-1 security (immediately or within 10 – 30 minutes) via security constrained economic dispatch (SCED) or other controls by increasing the output from the adjacent “energy park” generation to 330 MW
- This shows that studying the linked adjacent load and generation jointly results in secure transmission cases and therefore avoids upgrades that would be needed if they were studied separately

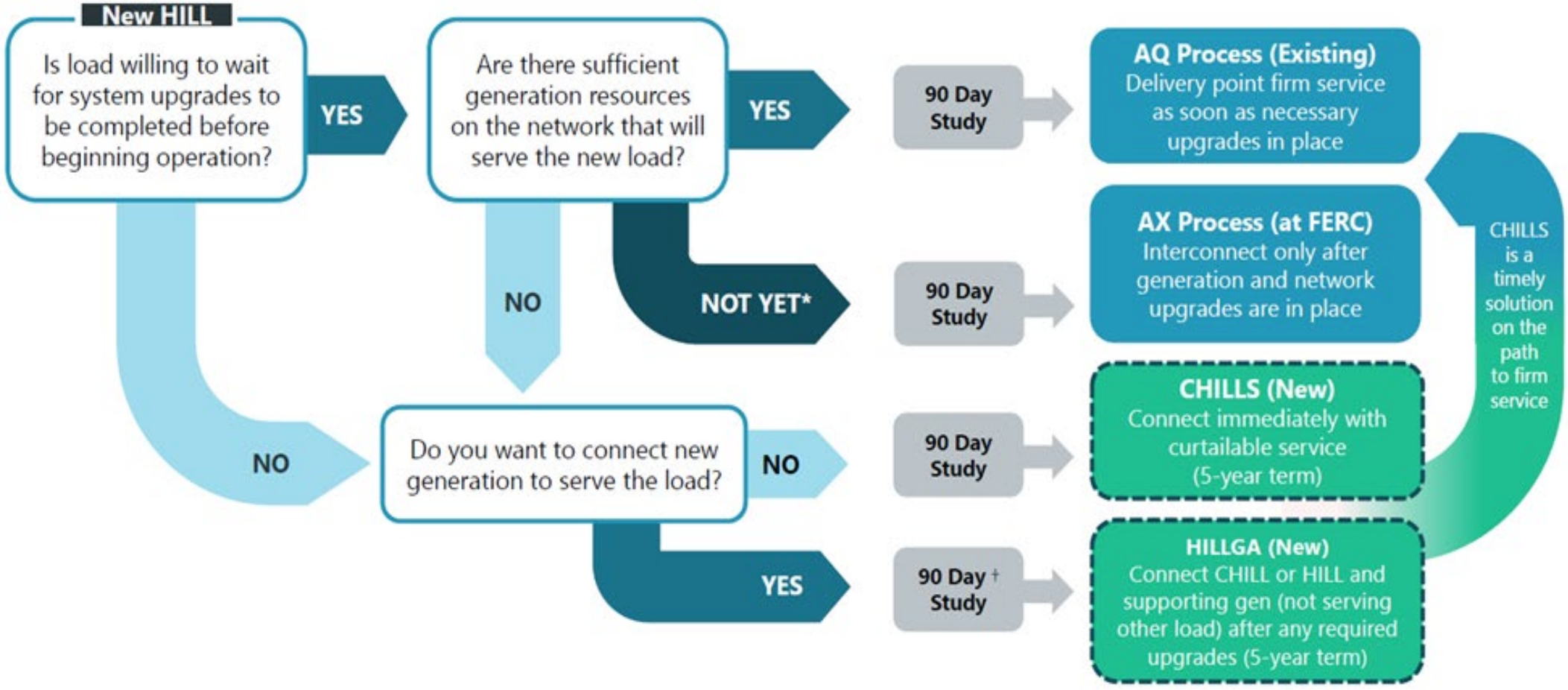


Benefits of BIGPAL Proposed Options

- **Flexible contracting** and risk allocation
  - Contractual risks with non-performance, ELCC degradation, counterparty risk can be internalized by (and privately allocated among) contracting parties, instead of being borne by PJM
  - This creates market-based solutions and signal for efficient capital allocation that encourages new supply to come online
- **Accelerates interconnection of new supply,** addressing fundamental problem of capacity supply shock
  - Pairing new adjacent generation with load can avoid significant network upgrades for load and generation reducing the time to interconnection and load integration
  - This brings new capacity online to serve large loads, reducing reliability shortfall and pressure on capacity market
- **No mandates** on curtailments or use of backup generation (backstop curtailments only)
  - Technology agnostic solution that allows a variety of resources to participate, be operationally linked and assume performance risk as a portfolio
- **Unlocks economic development** through accelerated generation interconnection
  - Other regions (e.g. SPP with HILLGA/CHILL) are pushing forward rapid 90-day interconnection for large loads and adjacent generation to maximize economic opportunities
  - PJM has recognized the need for new solutions that can ensure reliability and fairness for other market participants while meeting the needs of states and large loads to pursue economic development that may otherwise flow to other regions

Appendix

Appendix: 90-day Interconnection Process for New Adjacent Resources Builds on SPP HILLGA Proposal



SPP, Large Load Stakeholder Engagement Forum, July 2025

Appendix: BIGPAL Compared with PJM NCBL Proposal

Enhanced arrangement for and operational control of adjacent supply and load to allow parties to flexibly manage risks (ELCC accreditation, performance, counterparty), minimize curtailments, and gain faster interconnection

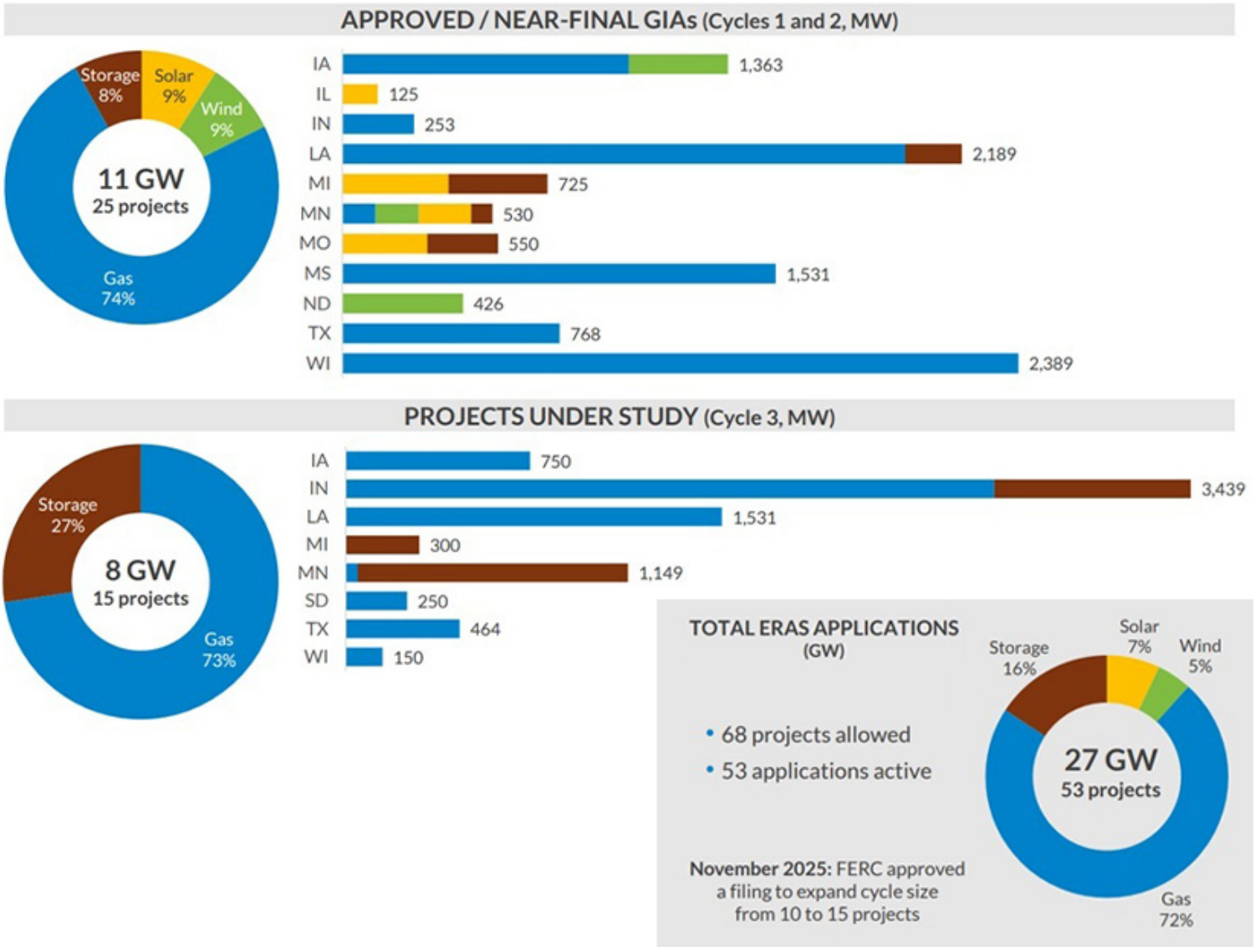
Risks	PJM NCBL + Current Bilateral Capacity Design	Brattle-Eolian BIGPAL Proposed Options
Gen (ELCC)	• PJM's tariff and accreditation methodology could change over the life of the asset • Generation faces ELCC risk during contracting with load with no flexibility on risk assignment between parties	• ELCC of linked portfolio hedges risk of individual resources • ELCC risk can be shared across gen & load in portfolio • Also hedges risk of ELCC changes
Load	• Load subject to curtailment pre-DR even if supply resources overperform ELCC during PAI • Penalty risk if load is offline and cannot curtail	• Performance risk shared across gen and load in the portfolio (with overperformance credited)
IX	• Generation goes through generator interconnection, load through load studies, no benefit from being nearby or contractually linked	• 90-day interconnection for generation that is adjacent and operationally linked with load

EXHIBIT 107-4

This is your first of five complimentary articles.

MISO: NERC to Dial Down RTO's Risk Level; Members Create Large Load Working Group

Listen to this story (#/)



(//www.rtoinsider.com/128949-miso-nerc-will-lower-risk-level-stakeholders-create-large-load-working-group/)

MISO's expedited interconnection queue totals as of early 2026 | *MISO*

Mar 25, 2026 | Amanda Durish Cook (//www.rtoinsider.com/author/amanda-cook/)

NEW ORLEANS — In a case of déjà vu, *MISO (https://www.rtoinsider.com/category/rto/rto-miso/)* announced that *NERC (https://www.rtoinsider.com/category/ero/ero-nerc-committees/)* is poised to issue a follow-up to its Long-Term Reliability Assessment that stands to lower the RTO's reliability vulnerability from "high risk" to "elevated."

MISO Vice President of System Planning Aubrey Johnson said NERC would issue the updated findings in early May.

Speaking at a March 24 meeting of the System Planning Committee of the MISO Board of Directors, Johnson said this time around, NERC would factor in MISO's interconnection queue fast lane, which boosts supply adequacy.

A NERC representative confirmed the agency would issue a special assessment in April.

The Bottom Line

For the second year in a row, NERC is to issue a postscript that tones down the level of risk MISO faces according to the agency's Long-Term Reliability Assessment.

MISO's separate, expedited interconnection queue has *attracted (https://cdn.misoenergy.org/20260324%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Generator%20Interconnection%20Queue%20Update745972.pdf)* 27 GW worth of proposals across 53 generation projects, 72% of which is natural gas, 16% storage, 7% solar and 5% wind. So far, MISO is ready to clear or has cleared 11 GW of nameplate capacity to connect and is studying an additional 8 GW for interconnection. (See *MISO's 3rd Expedited Queue: 8 GW of Gas and Batteries (https://www.rtoinsider.com/127770-miso-3rd-expedited-queue-8gw-gas-batteries/)*.)

MISO Director Nancy Lange said NERC's initial decision to ignore contributions from the expedited queue in its assessment is "puzzling." NERC officials have said the organization enforces a cutoff date for information that informs the assessment.

To submit a commentary on this topic, email forum@rtoinsider.com (mailto:forum@rtoinsider.com).

Director Mark Johnson said even the improved standing to "elevated risk" is "still a discount to what's being done" by MISO and its members to address reliability.

MISO Independent Market Monitor (IMM) David Patton told the RTO's board, executives and stakeholders he continues to believe NERC was off base to designate MISO a high-risk area.

Patton said "probably the most significant" consequence of NERC's LTRA is the U.S. Department of Energy issuing several 90-day retirement delays for coal plants in MISO's territory. He said the orders are racking up extraordinary costs.

The U.S. Department of Energy reupped stay-open orders March 24 for NIPSCO's R.M. Schahfer Generating Station and Centerpoint's F.B. Culley Generating Station through June 21, 2026.

Its pretty easy to come the conclusion that none of these orders are actually needed," Patton said at a March 24 meeting of the Markets Committee of the MISO Board of Directors.

Patton quipped that "nobody reads the report" and instead focuses on the vibrant colors on NERC's indicative map.

Multiple state regulators belonging to the Organization of MISO States sent a letter in February to challenge NERC's results and the omission of MISO's fast-tracked interconnection process. (See *MISO States Dispute 'High Risk' Designation from NERC (https://www.rtoinsider.com/125208-miso-states-dispute-high-risk-designation-from-nerc/)*.)

But at a March 25 Advisory Committee meeting, Clean Grid Alliance Executive Director Beth Soholt criticized MISO's efforts to bring more supply online for translating overwhelmingly into new gas generation.

"I'm wondering where the balance is in this 'all of the above' approach," Soholt said.

NERC similarly downgraded MISO's alert level in the LTRA in 2025 through an after-the-fact supplement. In that case, the IMM criticized NERC's original conclusion and pointed out an error: NERC used unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement.

In that instance, after a back-and-forth between MISO and NERC, the reliability corporation ultimately downgraded MISO from "high risk" to "elevated risk." (See *IMM: NERC Reliability Assessment Still Overstating MISO Risk (https://www.rtoinsider.com/109887-imm-nerc-reliability-assessment-still-overstating-miso-risk/)*.)

In February, MISO Senior Manager of Market Design Neil Shah told the Entergy Regional State Committee the RTO was in contact with NERC to hopefully improve assumptions used in the latest LTRA.

Shah said including the generator interconnection express lane would likely "close the gap" in the NERC report. However, he said uncertainty remains due to the potential for additional large loads claiming spots on the grid.

MISO expects the first projects from its expedited generator queue to come online in 2028. Beyond that, Shah said, "MISO is projecting higher rate of new resource additions in 2026" than have historically come online annually from 2022 to 2025.

Large Loads, Uptick in Supply Additions

NERC's revised findings are set to arrive as large loads continue to ratchet up in MISO and the RTO sets sights on record-setting capacity additions.

MISO's Advisory Committee at its March 25 meeting voted to create a Large Load Working Group, which would discuss ever-larger load integrations and report to the Advisory Committee. The new stakeholder group doesn't yet have a charter or management plan, but it will likely help develop ideas to better integrate demand.

MISO has indicated it will introduce reliability requirements for large loads at the time of interconnection and could file a proposal with FERC in late 2026.

During Board Week, MISO said its recent load estimates and its members' load forecasting show it could have more than 145 GW in load by 2030 and about 155 GW in 2035.

MISO and members' load projections through 2035 | *MISO*

MISO expects to add about 15 GW of capacity by the end of 2026. If realized, it would be a record for the RTO.

"The systems are responding. The work we're doing is really coming to fruition," Aubrey Johnson said of MISO's interconnection process.

MISO's legacy interconnection queue contains 192 GW, but the RTO expects that number to continue declining as federal tax credits are phased out. The grid operator faced a more-than-300-GW queue at one point in 2025.

MISO has recently issued $60 million in refunds to withdrawing interconnection customers, a figure significant enough to be featured in the RTO's financial updates.

Relatedly, the grid operator now has 76 GW in generation with approved interconnection agreements but has yet to be built.

"We predict that we will have close to 100 GW … by the end of the year," Johnson said at the System Planning Committee meeting.

Of the 76 GW, MISO reported that 42 GW are delayed three years or more beyond their stated commercial operation dates. Johnson said developers remain dogged by permitting hurdles, supply chain issues and, in some cases, the lack of an off-taker for their planned projects.

However, Johnson said MISO was able to process the first study phase of the regular 2025 cycle of interconnection projects in just 54 business days.

"And that's going to be the slowest we ever do it," Johnson said. "Going forward, we expect to only have one open queue cycle per year."

However, Soholt said she's heard that some interconnection customers don't trust the results Pearl Street's *SUGAR (https://pearlstreettechnologies.com/our-technology/)* software (which MISO is using to automate studies) is producing, noting interconnection customers are having difficulty replicating the study results they receive.

MISO BOARD OF DIRECTORS (//WWW.RTOINSIDER.COM/CATEGORY/RTO/RTO-MISO/RTO-MISO-BOD/)

NERC & COMMITTEES (//WWW.RTOINSIDER.COM/CATEGORY/ERO/ERO-NERC-COMMITTEES/)

RELIABILITY (//WWW.RTOINSIDER.COM/CATEGORY/RTO/RTO-PUBLIC-POLICY/RTO-RELIABILITY/)

RESOURCE ADEQUACY (//WWW.RTOINSIDER.COM/CATEGORY/RTO/RTO-RESOURCES/RTO-RESOURCE-ADEQUACY/)

KEYWORDS CLEAN GRID ALLIANCE (CGA) (//WWW.RTOINSIDER.COM/TAG/CLEAN-GRID-ALLIANCE-CGA/) DAVID PATTON (//WWW.RTOINSIDER.COM/TAG/DAVID-PATTON/) LARGE LOAD WORKING GROUP (//WWW.RTOINSIDER.COM/TAG/LARGE-LOAD-WORKING-GROUP/) LONG-TERM RELIABILITY ASSESSMENT (LTRA) (//WWW.RTOINSIDER.COM/TAG/LONG-TERM-RELIABILITY-ASSESSMENT-LTRA/) MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) (//WWW.RTOINSIDER.COM/TAG/MIDCONTINENT-INDEPENDENT-SYSTEM-OPERATOR-MISO/) MISO BOARD OF DIRECTORS (//WWW.RTOINSIDER.COM/TAG/MISO-BOARD-OF-DIRECTORS/) MISO BOARD WEEK (//WWW.RTOINSIDER.COM/TAG/MISO-BOARD-WEEK/) NORTH AMERICAN ELECTRIC RELIABILITY CORP. (NERC) (//WWW.RTOINSIDER.COM/TAG/NORTH-AMERICAN-ELECTRIC-RELIABILITY-CORP-NERC/)

(https://www.facebook.com/sharer/sharer.php?u=//www.rtoinsider.com/128949-miso-nerc-will-lower-risk-level-stakeholders-create-large-load-working-group/) (https://twitter.com/intent/tweet?url=//www.rtoinsider.com/128949-miso-nerc-will-lower-risk-level-stakeholders-create-large-load-working-group/&text=MISO%3A+NERC+to+Dial+Down+RTO%E2%80%99s+Risk+Level%3B+Members+Create+Large+Load+Working+Group) (https://www.linkedin.com/cws/share?url=//www.rtoinsider.com/128949-miso-nerc-will-lower-risk-level-stakeholders-create-large-load-working-group/) (mailto:?subject=MISO: NERC to Dial Down RTO's Risk Level; Members Create Large Load Working Group&body=//www.rtoinsider.com/128949-miso-nerc-will-lower-risk-level-stakeholders-create-large-load-working-group/)

AMANDA DURISH COOK
(//WWW.RTOINSIDER.COM/AUTHOR/AMANDA-COOK/)

We Energies Defers Oak Creek Coal Units' Retirement Through 2027
(//www.rtoinsider.com/129786-we-

(//www.rtoinsider.com/

We Recommend

1. A New Metric Related to Data Centers and Electricity that May Matter (//www.rtoinsider.com/129994-metric-related-data-centers-electricity-that-may-matter/)
   Apr 12, 2026 | Markets (//www.rtoinsider.com/category/rto/rto-markets/)
   Peter Kelly-Detwiler (//www.rtoinsider.com/author/peter-kelly-detwiler/)

2. ISO-NE Wholesale Costs Subside in March After Costly Winter (//www.rtoinsider.com/129920-iso-ne-wholesale-costs-subside-march/)
   Apr 9, 2026 | ISO-NE (//www.rtoinsider.com/category/rto/rto-iso-ne/)
   Jon Lamson (//www.rtoinsider.com/author/jon-lamsonrtoinsider-com/)

3. Reports Flag Soaring Costs, Delays for New Gas-fired Generation (//www.rtoinsider.com/129915-motives-costs-gas-generation-buildout-detailed-reports/)
   Apr 9, 2026 | Company News (//www.rtoinsider.com/category/rto/rto_company/)
   John Cropley (//www.rtoinsider.com/author/john-cropley/)

4. TeraWulf's Data Center Plans Draw Protests in FERC Review of Power Plant Purchase (//www.rtoinsider.com/129913-terawulf-plan-data-center-md-plant-draws-protests-ferc/)
   Apr 9, 2026 | Company News (//www.rtoinsider.com/category/rto/rto_company/)
   James Downing (//www.rtoinsider.com/author/james-downing/)

5. FERC Approves CAISO EDAM 'Transitional' Intertie Proposal (//www.rtoinsider.com/129907-ferc-approves-caiso-edam-intertie-proposal/)
   Apr 9, 2026 | CAISO/WEIM (//www.rtoinsider.com/category/rto/rto-caiso-weim/)
   Henrik Nilsson (//www.rtoinsider.com/author/henrik-nilsson/)

Popular Stories

Group Raises Questions over MISO IMM Involvement in $22B Tx Plan Complaint (//www.rtoinsider.com/128884-group-raises-questions-miso-imm-independence-22b-tx-portfolio/)

Mar 24, 2026 | Markets (//www.rtoinsider.com/category/rto/rto-markets/)
Amanda Durish Cook (//www.rtoinsider.com/author/amanda-cook/)

TOs Ask FERC to Suspend Competitive Bidding in MISO and SPP (//www.rtoinsider.com/129698-group-seeks-end-competitive-bidding-miso-spp/)

Apr 7, 2026 | MISO (//www.rtoinsider.com/category/rto/rto-miso/)
Amanda Durish Cook (//www.rtoinsider.com/author/amanda-cook/)

Demand Growth Leads to a New Round of an Old Debate in States: Restructuring (//www.rtoinsider.com/128613-demand-growth-leads-new-round-old-debate-states-restructuring/)

Mar 23, 2026 | Markets (//www.rtoinsider.com/category/rto/rto-markets/)
James Downing (//www.rtoinsider.com/author/james-downing/)

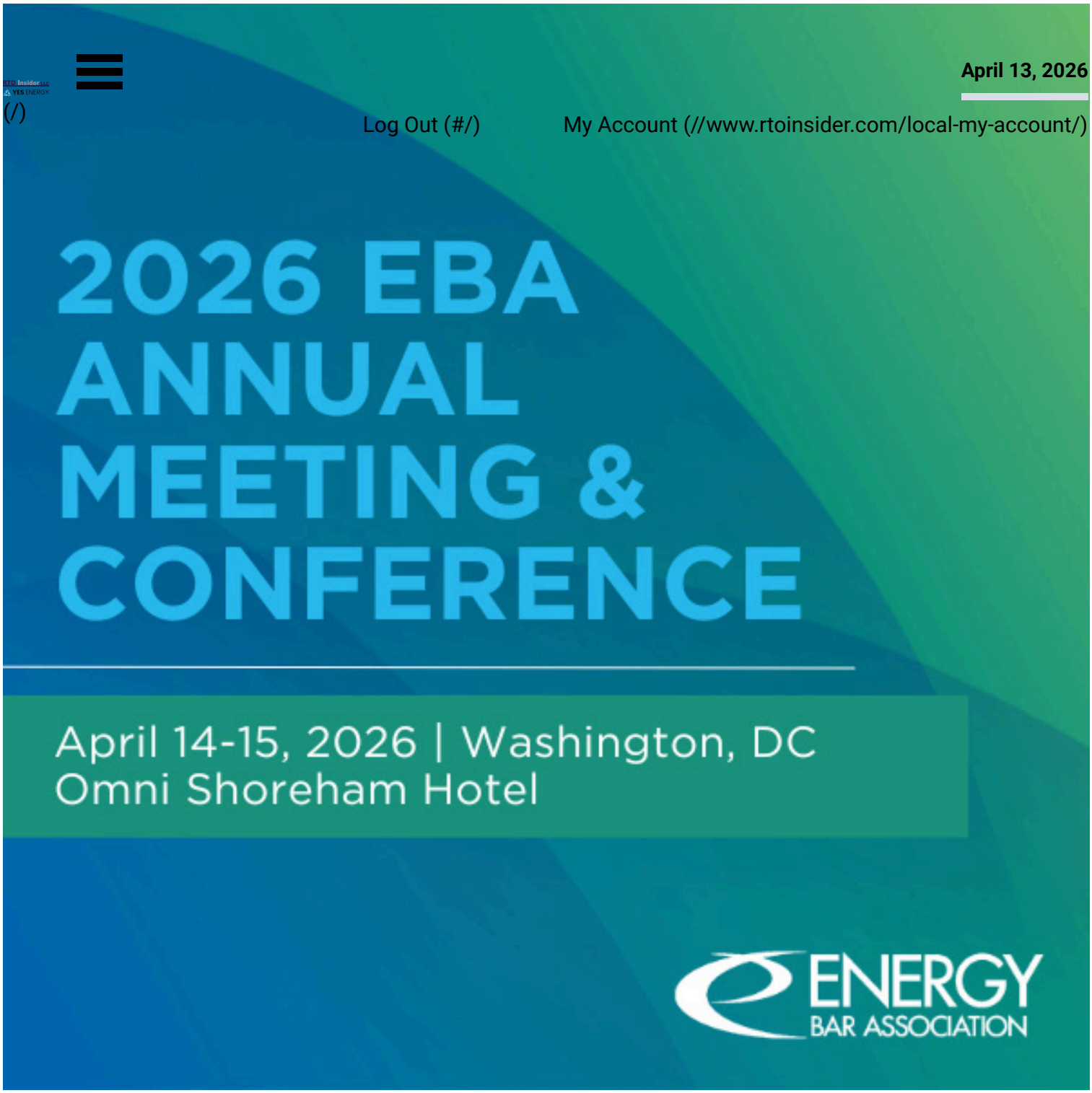
ERCOT Large Load Interconnection Queue Hits 410 GW (//www.rtoinsider.com/129421-ercot-large-load-requests-soar-again/)

Apr 1, 2026 | ERCOT (//www.rtoinsider.com/category/rto/rto-ercot/) | Tom Kleckner (//www.rtoinsider.com/author/tom-kleckner/)

Regulators Past and Present Ask MISO for Public Findings on IMM Link to LRTP Complaint (//www.rtoinsider.com/129309-regulators-ask-public-results-potential-miso-imm-link-lrtp-complaint/)

Mar 31, 2026 | MISO (//www.rtoinsider.com/category/rto/rto-miso/)
Amanda Durish Cook (//www.rtoinsider.com/author/amanda-cook/)

Industry Gatherings



(https://www.eba-net.org/home/2026-eba-annual-meeting-and-conference/)

(https://www.eba-net.org/event/2026-cfeba-annual-gala/)

(https://www.infocastinc.com/event/new-york-energy)

Publications (/#)

RTO Insider (/rto-insider)

AESO (//www.rtoinsider.com/category/rto/aeso/)
CAISO/WEIM (//www.rtoinsider.com/category/rto/caiso-weim/)
Company News (//www.rtoinsider.com/category/company/)
ERCOT (//www.rtoinsider.com/category/rto/rto-ercot/)
FERC & Federal (//www.rtoinsider.com/category/rto/rto-ferc-federal/)
IESO (//www.rtoinsider.com/category/rto/ieso/)
ISO-NE (//www.rtoinsider.com/category/rto/rto-iso-ne/)
Markets (//www.rtoinsider.com/category/rto/rto-markets/)
MISO (//www.rtoinsider.com/category/rto/rto-miso/)
NYISO (//www.rtoinsider.com/category/rto/rto-nyiso/)
PJM (//www.rtoinsider.com/category/rto/rto-pjm/)
Public Policy (//www.rtoinsider.com/category/rto/rto-public-policy/)

ERO Insider (/ero-insider)

FERC & Federal (//www.rtoinsider.com/category/ero/ferc-federal/)
NERC & Committees (//www.rtoinsider.com/category/ero/nerc-committees/)
Regional Entities (//www.rtoinsider.com/category/ero/regional_entities/)
Resource Adequacy (//www.rtoinsider.com/category/ero/ero-resource_adequacy/)
Standards/Programs (//www.rtoinsider.com/category/ero/standards-programs/)
State Regulation (//www.rtoinsider.com/category/ero/ero-state_regulation/)

Additional Links (#/)

About Us (/about-us)
Yes Energy (https://www.yesenergy.com)
Why Subscribe? (/subscribe)
FAQ (/faq)
Terms (/subscription-agreement)
Privacy Policy (/privacy-policy)
Cookie Policy (/policy/cookie)
News Alerts (/local-my-account/#newsalerts)

Contact Us (#/)

Rich Heidorn Jr.
(mailto:rich.heidorn@rtoinsider.com)
Editor-in-Chief & Publisher

Ken Sands
(mailto:Ken.Sands@rtoinsider.com)
Senior Vice President, Editorial

Adam Schaffer
(mailto:adam.schaffer@rtoinsider.com)
Senior Vice President, Business

RTO Insider/Yes Energy
5500 Flatiron Parkway
Suite 200
Boulder, CO 80301
(301) 658-6885

(https://facebook.com/rtoinsider/)

(https://twitter.co

(https://linkedin.com/company/3326640?trk=tyah)

Copyright © 2026 All Rights Reserved | Privacy Policy (/privacy-policy) | Terms Of Use (/subscription-agreement).

EXHIBIT 108

Grid Strategies

Review of NERC's 2025 Long-Term Reliability Assessment

Adria E. Brooks, Michael Goggin, John D. Wilson

March 5, 2026

Prepared for Earthjustice, Natural Resource Defense Council, Sierra Club, and Environmental Defense Fund

Table of Contents

1. Executive Summary
2. Generation resource assumptions
3. Interregional transmission assumptions
4. Demand assumptions
5. Extreme event energy adequacy
6. Conclusions and solutions
7. Methodology

Executive Summary

The NERC LTRA assesses future regional resource adequacy risk. Re-assessment using a more complete accounting of generation, imports, and demand from other data sources results in lower risk.

Overall, the LTRA resource margins are much tighter than what may occur for four reasons.

First, the LTRA underestimates likely-to-connect power resources. Power resources in advanced development stages are projected to provide enough capacity to resolve the majority of shortfalls identified in the LTRA.

Second, the most significant risk to resource adequacy shortfalls are delays to generator interconnection. Actions that delay interconnection study, permitting, and/or construction for generation facilities increase the likelihood of shortfalls.

Third, the LTRA underestimates imports from one region to another. At levels seen historically during extreme events, these are sufficient to further alleviate resource inadequacy.

Furthermore, additional interregional transmission would lessen shortfall risk. The NERC-identified interregional transfer capability additions would help resolve many of the identified seasonal capacity and energy shortfalls.

Fourth, data centers may require significantly less power than expected. Combined with the other three corrections, this scenario could allow all regions to meet 2030 peak summer load and reserve needs.

With a clearer vision of the future and rapid action, the grid could be even more reliable in five years than it is today.

NERC's 2025 Long-Term Reliability Assessment is too pessimistic. This analysis explores three major categories of input assumptions that impact the regional risks NERC identified.

North American Electric Reliability Corporation (NERC)'s Long-Term Reliability Assessment (LTRA) importantly captures potential reliability issues for a snapshot in time. NERC relies on utility-reported input data in making its assessments. This data, by definition, does not account for national power sector trends or limitations—such as double-counting of prospective demand or generation—that can have large impacts on future risk.

In this analysis we compare NERC's input data and assumptions against other sources to explore how changes to inputs impact the severity of risk identified in the LTRA. We explore three categories of inputs: demand, generation resources, and interregional transmission.

As the LTRA highlights, reserve margins—the difference between electricity demand and available supply—are tightening across the country. We find that while these margins are tightening, the severity of that risk is likely less than reported in the LTRA.

Three major factors:



Generation Resources



Interregional Transmission



Demand for electricity

GridStrategies

SOURCE | NERC "2025 Long-Term Reliability Assessment (LTRA)" (Jan. 2026)

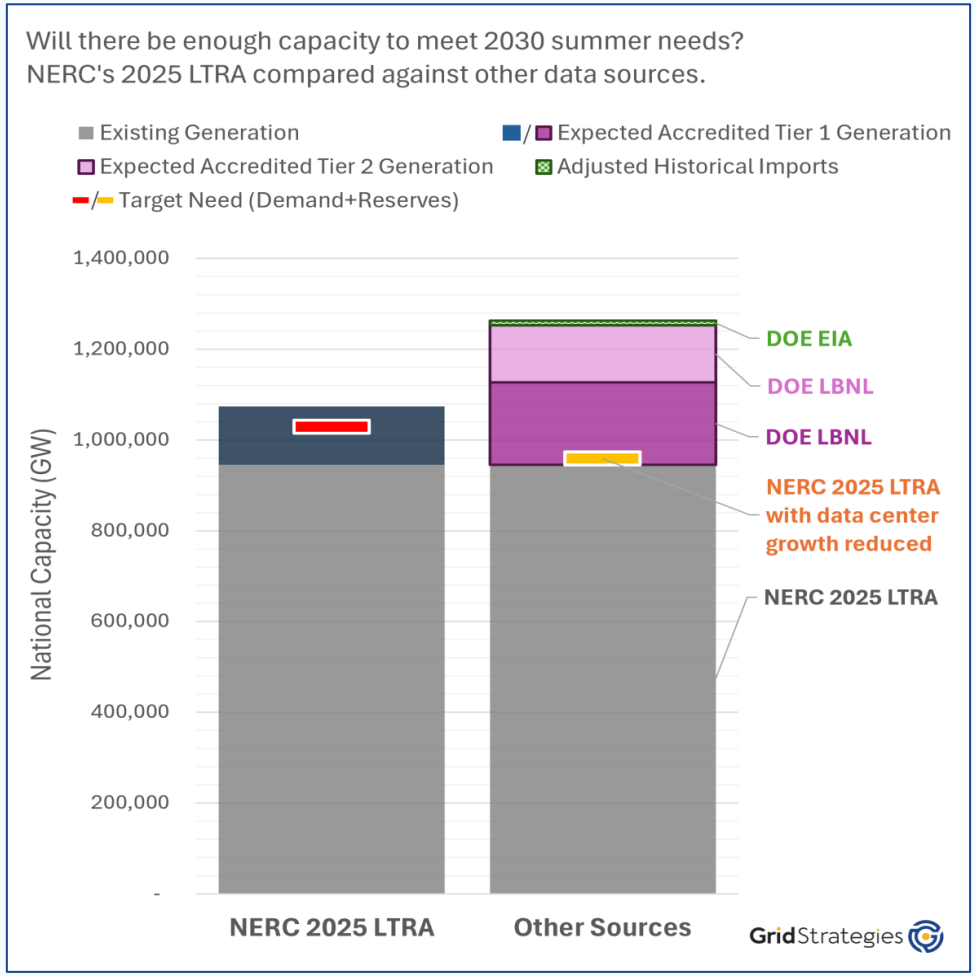
NERC's 2025 LTRA highlights important reliability concerns, but the severity of these concerns depends on the data used.

A reassessment of the LTRA regional seasonal adequacy using a more complete accounting of generation, imports, and demand from other data sources reveals different—and in many cases less dire—risk assessments for some regions.

- The LTRA generation forecast is based on an incomplete accounting of nearly built generation projects. A more reasonable expectation for generation growth can be determined from each region's interconnection queue.
- The LTRA import forecast excludes the opportunity for increased imports from new interregional transfer capability.
- The LTRA demand forecast is supplied by utilities and regional planners. The vast majority of the load growth in the LTRA forecast is based on utility large load forecasts. Some of this load is uncommitted and may not materialize or it may curtail during peak periods.

The combination of low generation, low import, and high demand assumptions used in the 2025 LTRA resulted in resource margins appearing tighter than may actually materialize.

A comparison of the aggregated resource margins from NERC's LTRA and other national, reputable data sources, which account for the above three factors, is shown to the right. This chart is explained in the Methodology.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025; Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Implementing currently available solutions will help all regions alleviate the identified capacity and energy risks.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

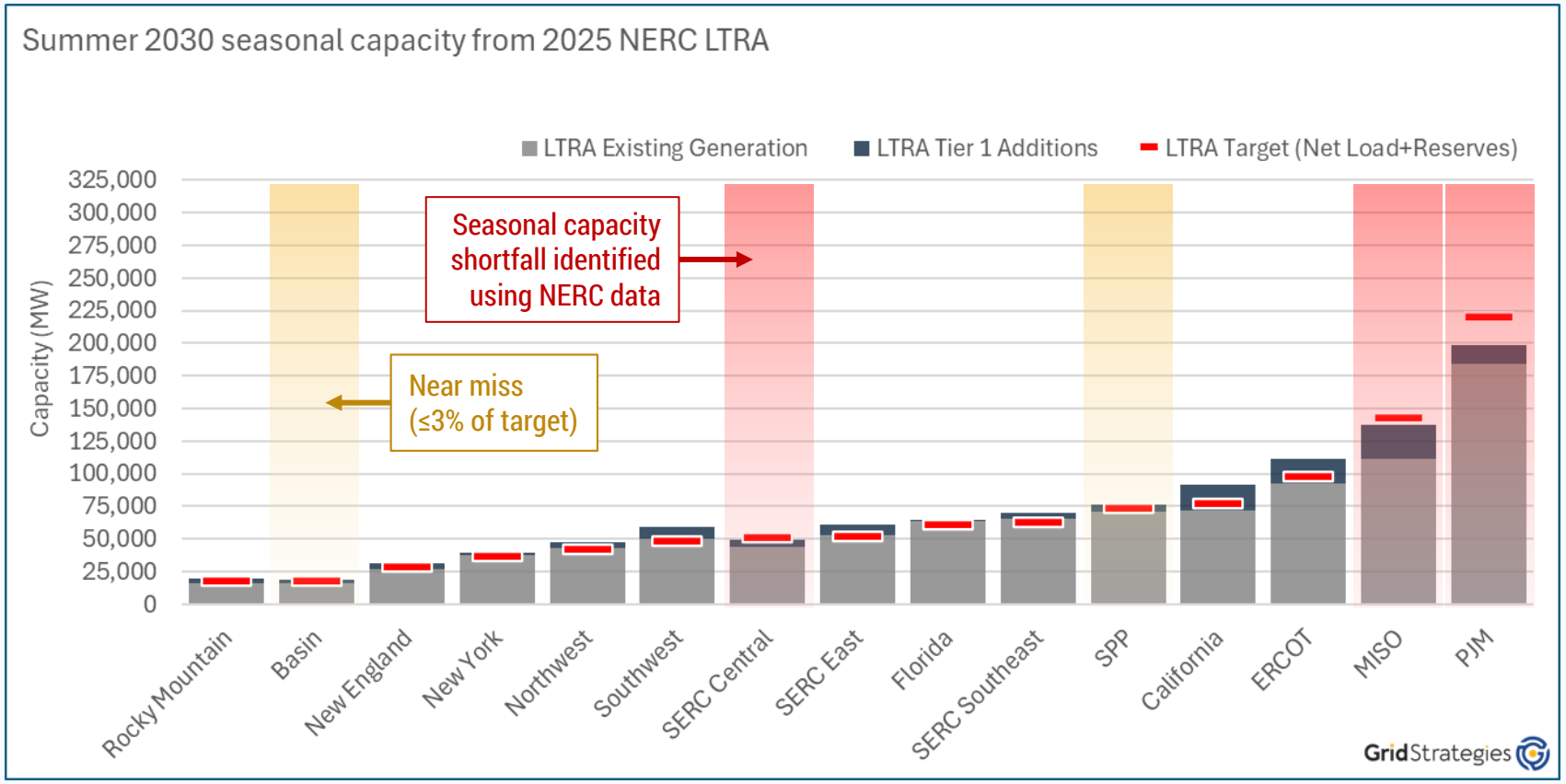
- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Generation Resource Assumptions

NERC only considered resources with executed interconnection agreements when determining shortfall risk.

All resources must undergo interconnection studies to identify any grid upgrades that may be necessary to reliably connect. At the end of the interconnection queue process, an interconnection agreement (IA) is executed. NERC considers any resource that has an executed IA as **Tier 1**.

To be resource adequate, a region must have enough future capacity and imports to meet load and reserve margins ("target"). NERC only counts Tier 1 resources toward future resources in the LTRA. NERC identifies three regions* that may be short of 2030 summer capacity needs using its assumptions. Two regions only exceed their target by less than 3%, marked here as "near miss" regions.



*NERC did not identify SERC Central as a heightened risk region though it is shown to be short of future capacity using the LTRA source data, perhaps because they did not identify elevated energy inadequacy risk despite the seasonal capacity shortfall in the region. We highlight it as elevated risk given the identified seasonal capacity shortfall.

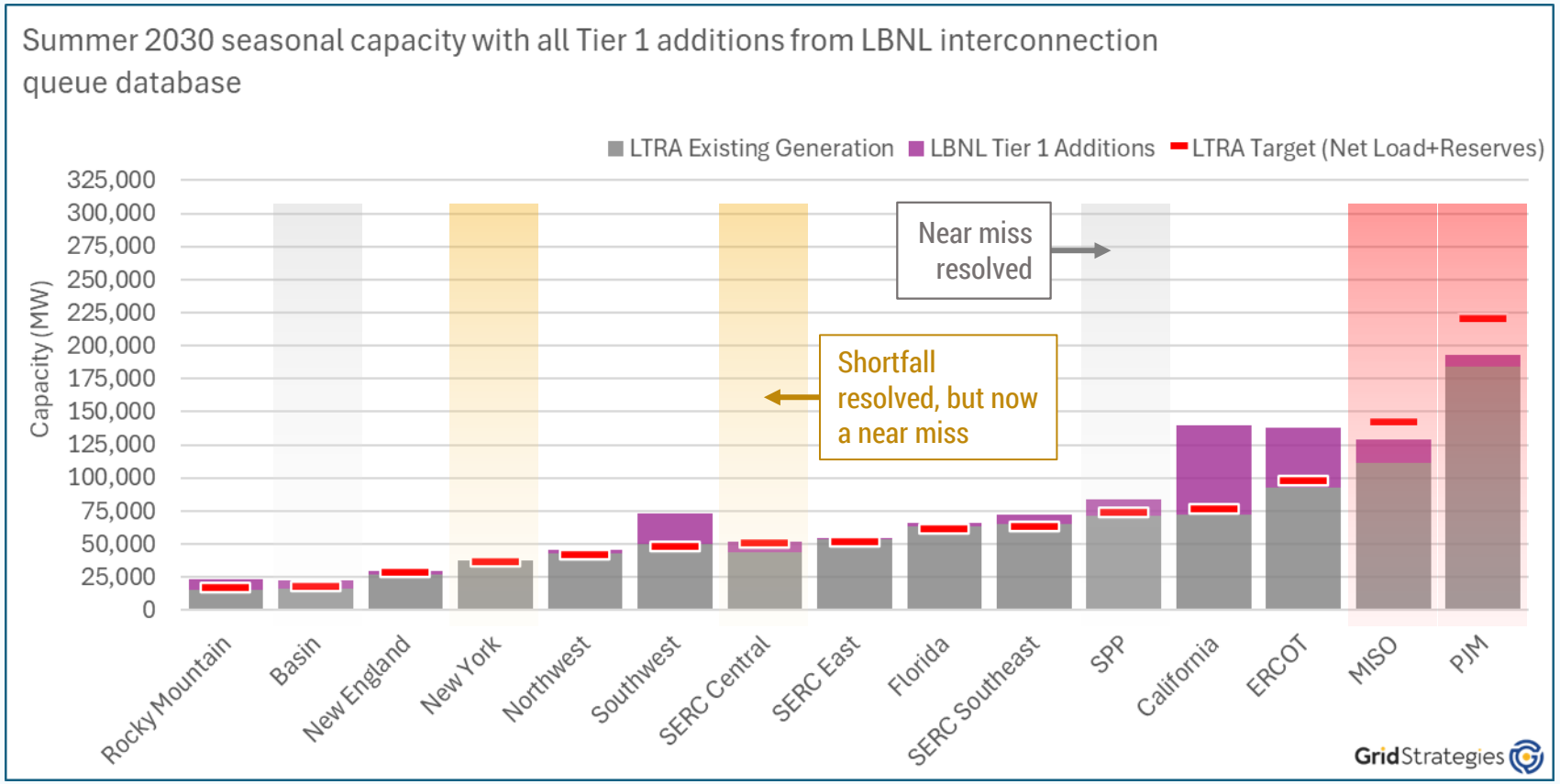
GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "2025 Electricity Supply & Demand (ES&D)" (Jan. 2026)

The amount of resource capacity with executed interconnection agreements in the LTRA is lower than that compiled by LBNL.

The U.S. Department of Energy (DOE)'s Lawrence Berkley National Laboratory (LBNL) tracks interconnection queue data across all regions and is a reputable source of high-quality data. The LBNL data suggests more accredited **Tier 1** resource capacity is available nationwide than is recorded in the LTRA, though regional allocations vary. The mismatch in data could be due to different processing methods, collection periods, and, importantly, resource accreditation methods.*

Using the LBNL data paints a different future risk picture than the LTRA—only two regions show 2030 summer shortfalls. This highlights how sensitive risk assessments are to their input data.



*All LBNL generation capacity used in this analysis has been discounted using regional, seasonal, and resource-specific accreditation methods, to show the expected generation capacity during peak load. Utilities do not uniformly report seasonal or resource-specific accredited capacity to NERC for use in the LTRA, which, as NERC highlights, may inaccurately account for the capacity availability during peak load (LTRA at 9, 44, 60, 71, 76, 122). See the Methodology for more information.

GridStrategies

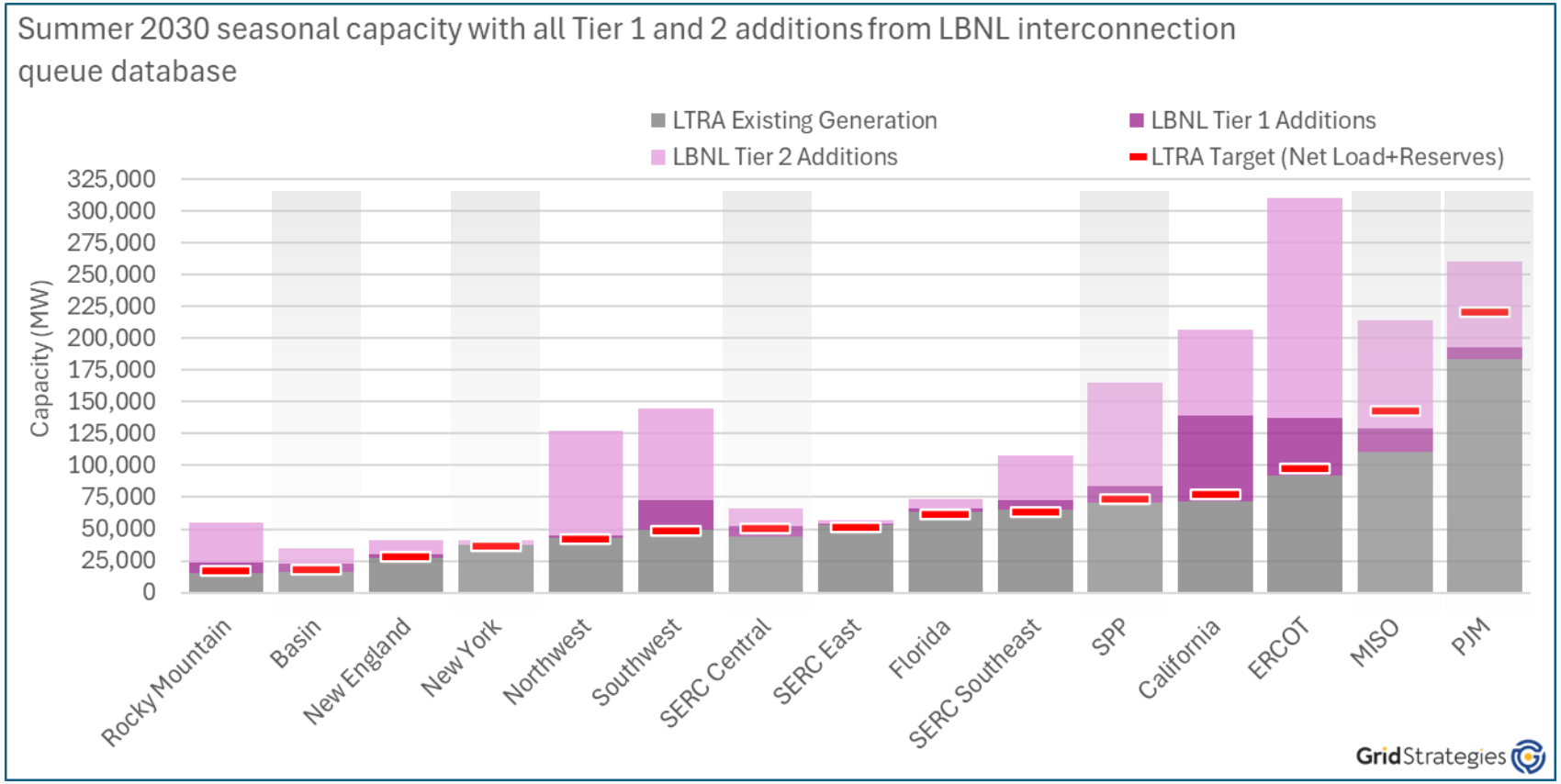
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (Aug. 2025)

There are more resources under development in each region than those with executed IAs. Providing a path to interconnection for these resources helps alleviate risk.

NERC considers any resource that has begun system studies, but has not yet completed them, to be a **Tier 2** resource. According to LBNL data, there is nearly five times the accredited Tier 2 resource capacity with planned in-service dates by 2030 nationwide than NERC-counted Tier 1 as well as three times the NERC-counted Tier 2 summer 2030 resource capacity.

NERC does not include any Tier 2 capacity in the LTRA shortfall analysis. Inclusion of this capacity suggests that regions could be at less risk of seasonal shortfalls than illustrated in the LTRA.

But this is only true if there are clear pathways for interconnection of these resources. LBNL research shows that generators are facing increasing delays in the interconnection study and post-study phases. These delays contribute to project cancellations, which is dangerous for seasonal resource adequacy.



GridStrategies

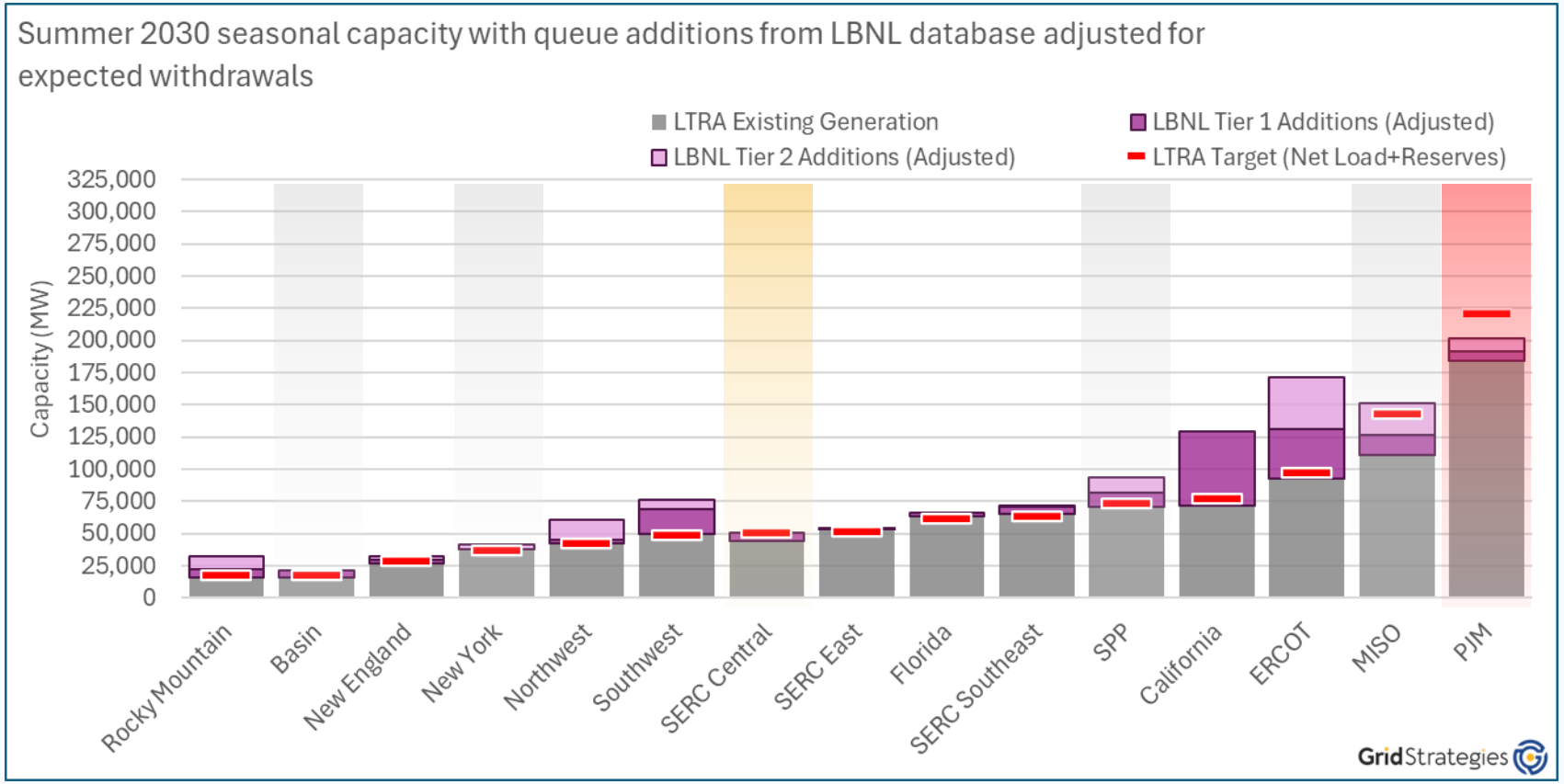
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Even when accounting for likely resource cancellations in the queue and post-queue phases, LBNL data suggests enough resources could connect to meet most regions' 2030 capacity needs.

It is unlikely that all Tier 1 and Tier 2 resources will connect to the grid. LBNL analysis shows as much as 85% of resources that enter the queues fails to connect to the grid ("withdrawal rates"), including facilities with executed IAs.

Rather than omit all Tier 2 data to account for the risk of cancellations (as done in the LTRA), we apply historic region-specific and phase-specific withdrawal rates to the LBNL data to estimate how much may connect to the grid by 2030.

Consideration of likely-to-connect resources currently in the interconnection queues resolves the majority of identified seasonal adequacy shortfalls. The resolution of shortfalls shown here is accomplished without a delay to announced resource retirements.



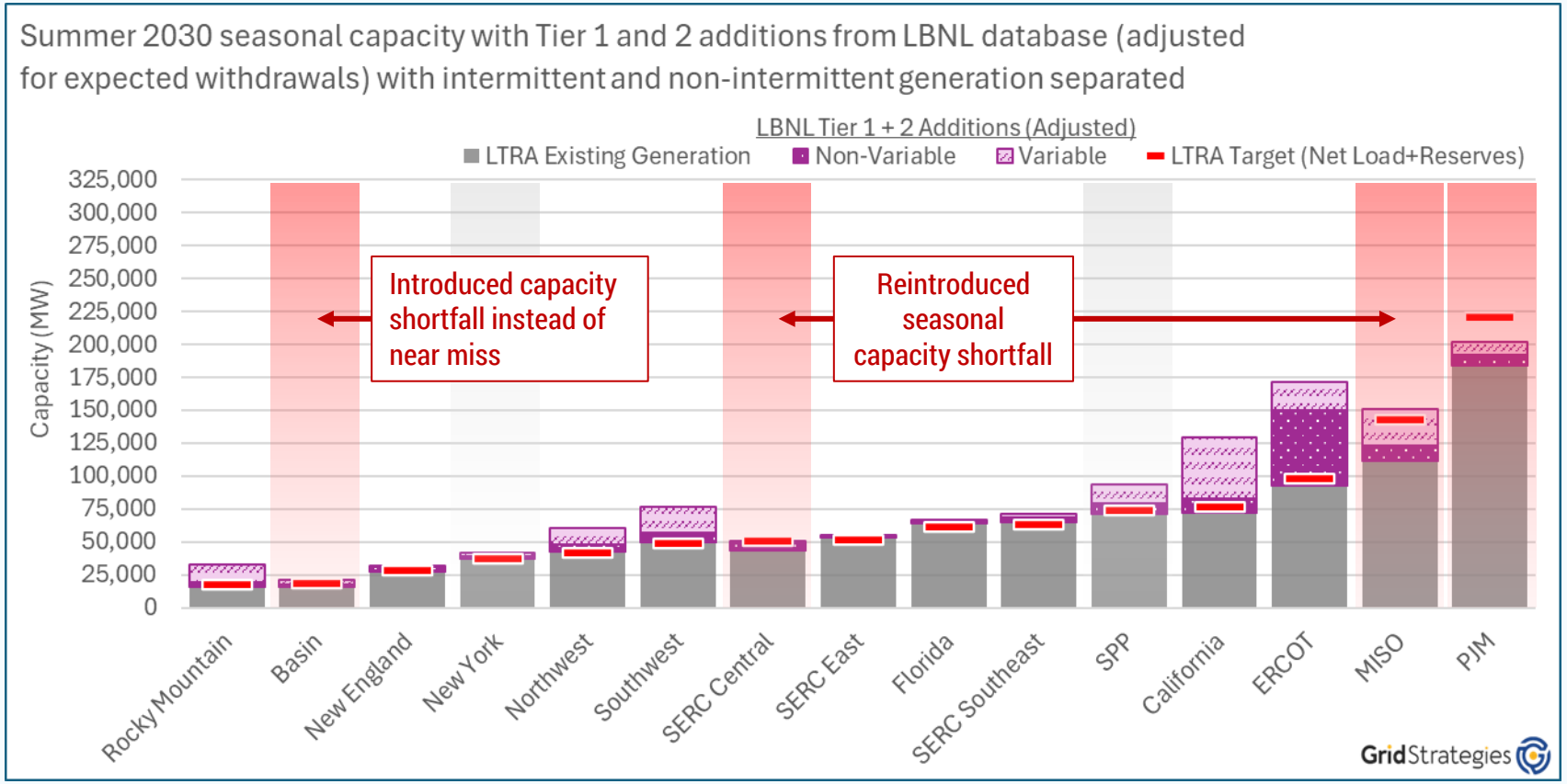
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Delays in the study, permitting, and/or construction phases to resources already in the queues—including wind and solar facilities—could jeopardize meeting regional seasonal capacity needs.

Additional permitting or equipment procurement steps applied to facilities increases their time to interconnection or results in project cancellation outright. Unnecessary hurdles for facilities waiting to interconnect could jeopardize huge amounts of resource capacity in advanced stages of development.

Shown here is the amount of likely-to-connect Tier 1 and 2 resource capacity from the LBNL data, broken out into variable (wind and solar) and non-variable resources.

Actions which delay permitting or construction for variable generation facilities could prevent large portions of the Midwestern, Southeastern, and Western regions from maintaining resource adequacy where they otherwise would be able to.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

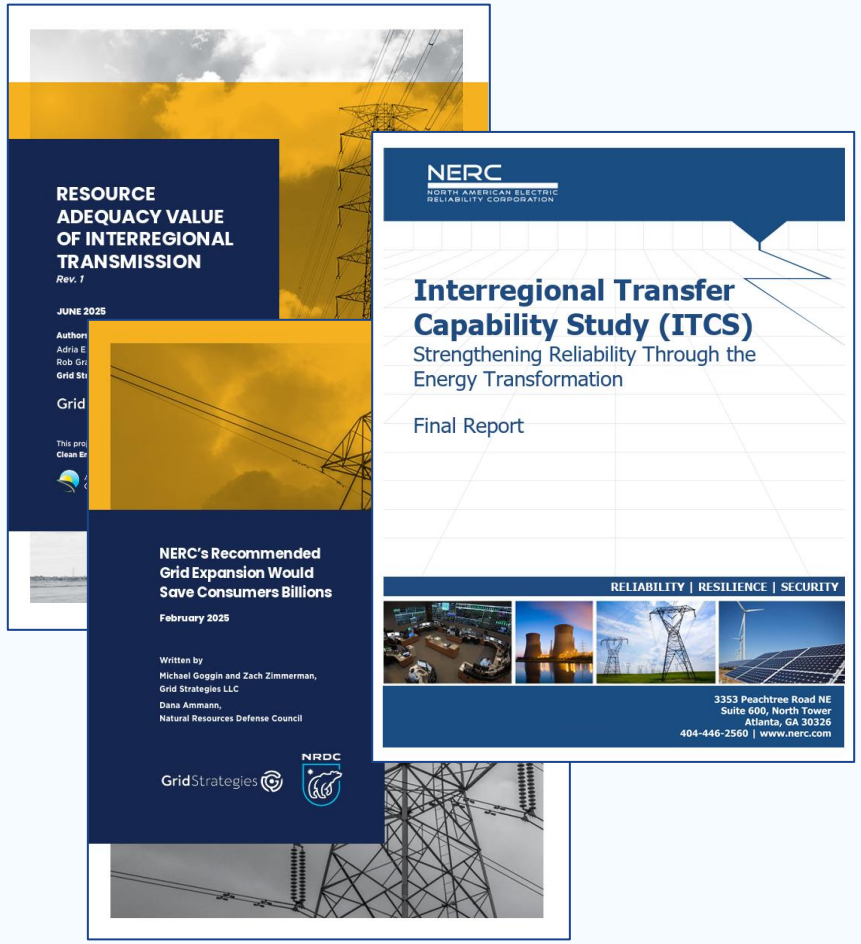
Interregional Transmission Assumptions

Interregional transmission helps to alleviate capacity adequacy concerns, especially during times of grid stress.

One of the many benefits of interregional transmission is the ability to move power between regions during times of grid stress. The availability of imports is primarily due to net load diversity among regions due to timing differences in peak demand and generation unavailability, particularly during severe weather events. Weather patterns and extreme grid events do not impact all regions equally, so there is often spare capacity in a neighboring region that could be shared during times of need. As a result, this benefit will largely persist even if reserve margins in neighboring regions are lower going forward. This phenomenon is well documented in several studies.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores the historical role of "non-firm" imports, which are available during extreme events. For example, MISO imported over 13 GW during Winter Storm Uri, of which 5 GW was in turn exported to SPP, imports that literally kept the lights on in those regions.

Sharing of power can only occur, of course, if enough interregional transmission exists to move the available power. NERC acknowledged this in their 2024 Interregional Transfer Capability Study (ITCS) where they measured the amount of interregional transmission capacity that should be added to each region to help support energy adequacy. The ITCS analysis looks at peak grid stress days for each region and determines if excess capacity is likely to be available in neighboring regions during those same hours. It then suggests interregional transmission capacity be added to move that excess generation.



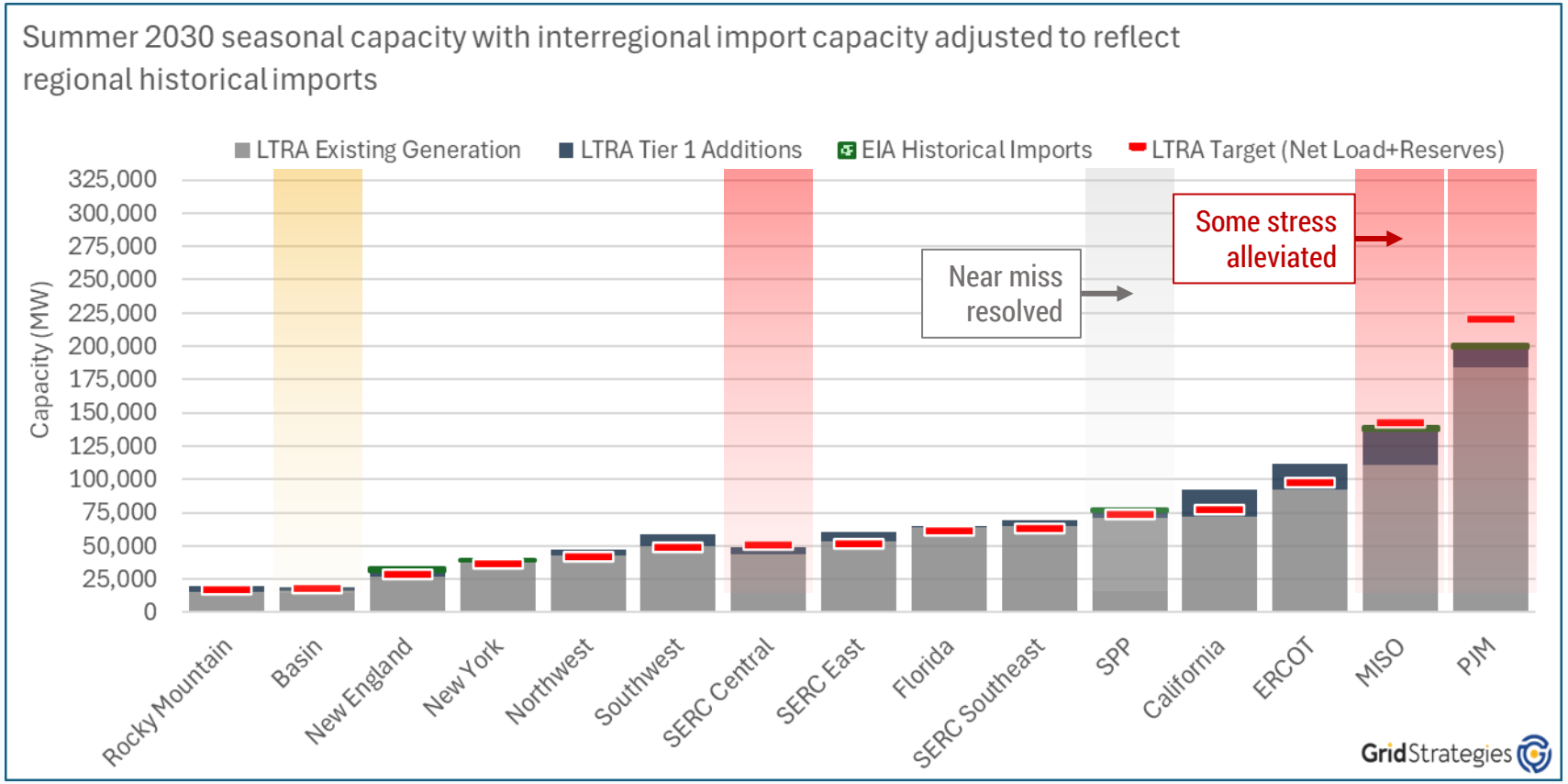
Source | NERC "Interregional Transfer Capability Study" (2024); Goggin, M., Zimmerman, Z., Amman, D., "NERC's Recommended Grid Expansion would Save Consumers Billions" (2025); Brooks, A., Silverstein, A., Gramlich, R., "The Resource Adequacy Value of Interregional Transmission" (2025)

The LTRA only counts firm imports, omitting non-firm imports. Some regional stress is alleviated when combining the LTRA capacity assumptions with historical non-firm import availability.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores non-firm imports over interregional transmission lines that have been available during historical grid stress events.

Hourly regional import and export data collected by the U.S. Energy Information Administration (EIA) confirm regions import significantly more during periods of peak demand than the LTRA assumes.

The inclusion of non-firm imports that are historically available during extreme events helps further alleviate resource inadequacy.



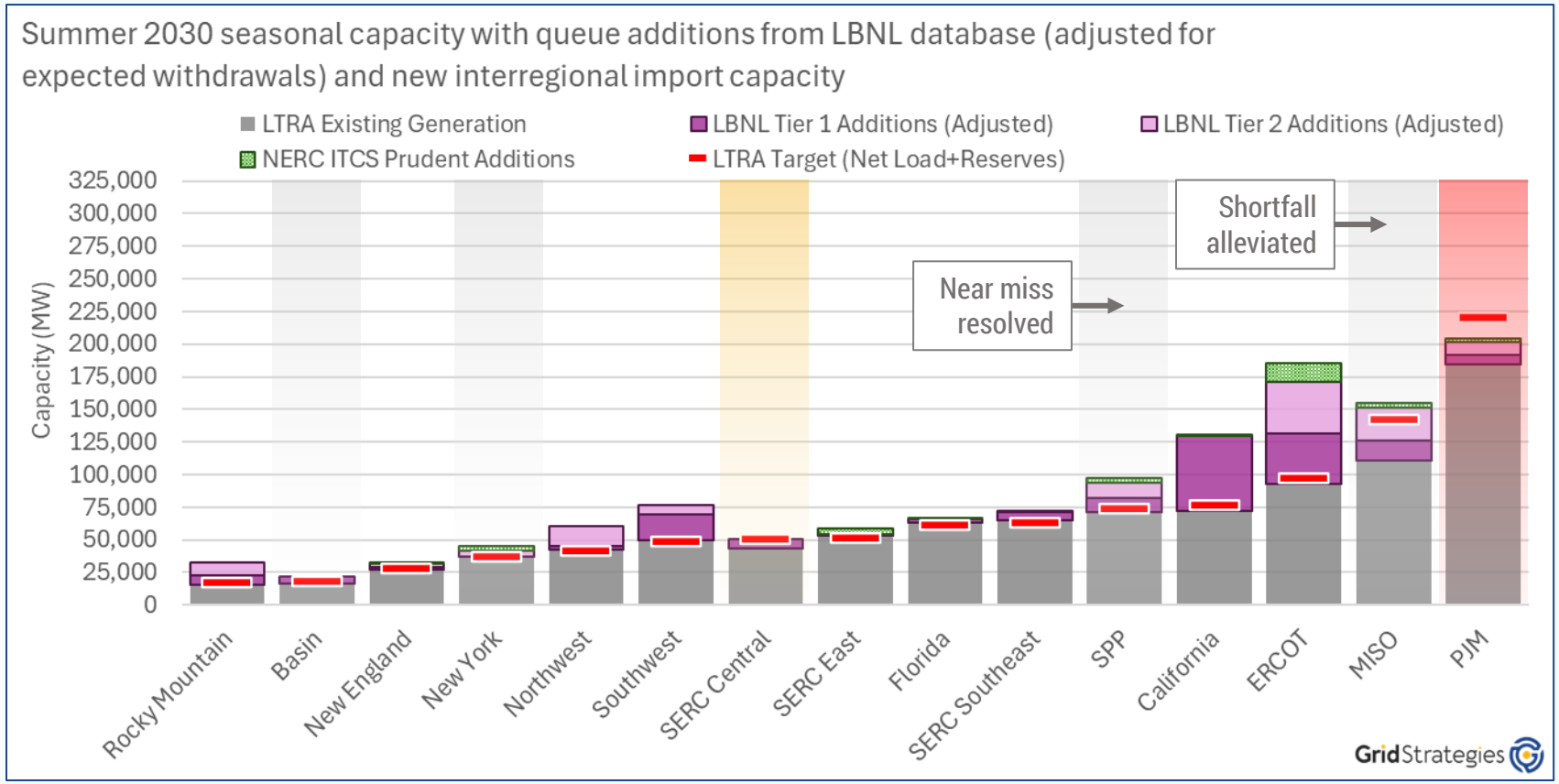
SOURCE | NERC "LTRA" (Jan. 2026); NERC "ES&D" (Jan. 2026); U.S. EIA "About the EIA-930 data" (accessed Feb. 2026)

The combination of NERC-identified increased transfer capability and reasonable resource assumptions from the interconnection queues provides even more security to avoid shortfalls.

The combination of interregional transmission additions suggested by NERC's ITCS and reasonable generation additions using LBNL queue data would provide regions with additional capacity to weather seasonal grid stress events.

The addition of new NERC-identified transfer capability would likely resolve many of the identified seasonal capacity and energy shortfalls.

All transmission takes a long time to develop, but this is especially true for interregional transmission. Unfortunately, the NERC-identified interregional transfer capability additions are unlikely to be built by 2030 under the status quo. Legislative and regulatory action taken now could accelerate the construction of these prudent additions.



GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Demand Assumptions

The load growth in the LTRA is based on utility projections that, in some cases, are based on overstated assumptions.

NERC compiled the LTRA load growth forecast by rolling up projections from utilities and regional grid operators. Large load forecasts are uncertain and could overstate load growth for several reasons.

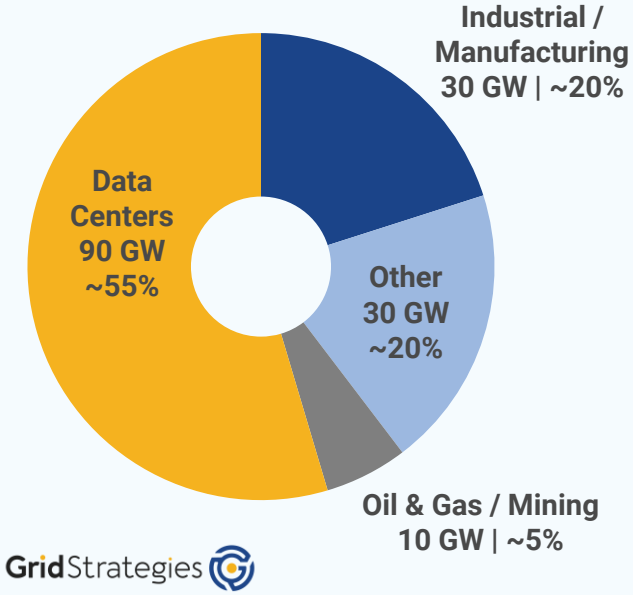
Reliance on customer data: Large load forecasts rely primarily on customer-supplied information.

- Data centers, in particular, are constrained by global supply chains. There is no clear method for individual load forecasts to account for how supply chain constraints will affect specific projects.
- Load forecasts lack visibility into customers' overall business plans. There may be "double counting" as data center operators develop more sites as options than they intend to build. The LTRA includes all loads with "development commitments necessary to drive grid planning studies." In contrast, the LTRA only counts generators that have completed all planning studies and signed an interconnection agreement.
- Many regulated utilities have an incentive to overstate load growth and interconnection success rates to justify additional rate-based investments in generation and other infrastructure.

Time lags: Producing and compiling load growth projections occurs months before the LTRA is released. Mounting delays in large load interconnection and policy changes appear to have slowed load growth since their compilation.

- Load interconnection queue backlogs and long lead times for power transformers and circuit breakers needed for interconnection are likely to delay commercial operation of many large load projects.
- As outlined in the following slides, new large loads from data centers, cryptocurrency mining, and hydrogen electrolysis could each face headwinds that are not fully accounted for in the LTRA.
- Recent policy changes are reducing load growth, such as the recent termination or restriction of federal tax credits for electric vehicles, heat pumps, hydrogen electrolysis, and advanced manufacturing.

Drivers of Load Growth (2025 – 2030)



Load flexibility: Regulations and utility tariffs are beginning to require some large loads to provide demand response or backup generation during periods of peak demand. ERCOT's load forecast includes substantial demand response for crypto mining facilities and assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%.

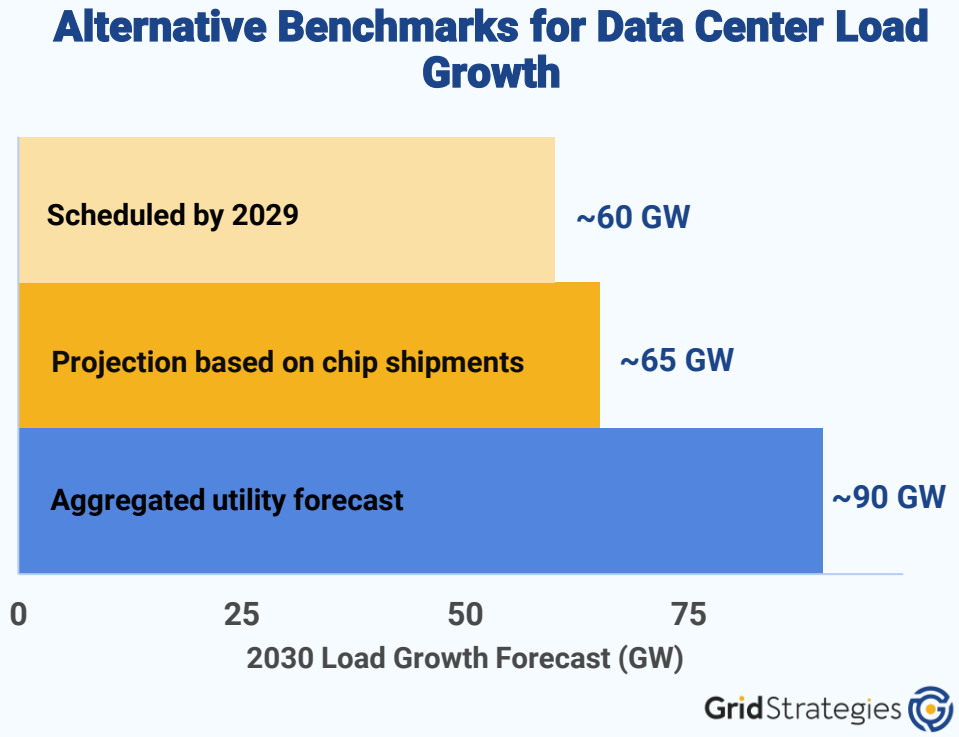
GridStrategies

SOURCE | Wilson, J., et al. "Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers" (Nov. 2025)

Assumed data center load

The LTRA reasonably states that, “New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.” However, the growth of data centers and their contribution to peak demand may be overstated due to:

- **Supply chain shortages of chips and other key inputs.** TD Cowen estimated that due to chip limitations, U.S. data center growth would be limited to 65 GW (orange bar), about two-thirds of the data center growth assumed for the U.S. alone in the LTRA (blue).
- **Financial constraints.** Wall Street analysts have expressed concerns that expected revenues are insufficient to sustain the overall industry trajectory for AI data center investment.
- **Load flexibility.** Data centers may be able to use local generation and storage resources to reduce or eliminate their on-peak demand for grid power. Additionally, some types of data centers may opt to curtail their demand during peak periods without local supply. Curtailment activities such as these are unlikely to appear in utility forecasts of expected load. These practices may drive up annual energy use.



GridStrategies

SOURCE | TD Cowen, Data Centers, Generative AI, & Power Constraints: The Path Forward (May 2024); Bain & Company, “$2 trillion in new revenue needed to fund AI’s scaling trend” (Sept. 2025); Wilson, J., et al. (2025)

Assumed cryptocurrency mining load

Cryptocurrency mining accounts for about 7 GW or 15% of ERCOT's projected large load growth through 2030, though it is likely lower in other regions.

However, cryptocurrency mining data centers are understood to be more speculative than other data center types. Cryptocurrency mining facilities are highly modular and can be readily moved to different sites, even after they have been installed and put into service at a site. Unlike some types of data centers, they do not face major siting constraints due to concerns about latency or access to fiber networks. These factors increase the likelihood of "double counting."

In ERCOT, cryptocurrency mines routinely use demand response or price-sensitive demand bids to curtail demand during peak periods. If properly incentivized to do so, their contribution to peak demand can be reduced or eliminated.

Assumed Hydrogen Electrolyzer Load

Most hydrogen production load is forecast in ERCOT, where planned electrolyzers account for about 8-9 GW or 20% of ERCOT's projected large load growth through 2030. NYISO's load forecast used to include substantial hydrogen production, but it has been adjusted downward. Only a few other load forecasts mention hydrogen production, and at much lower volumes than in ERCOT. According to EIA data, the U.S. had only 116 MW of hydrogen electrolyzers in operation in 2024.

ERCOT's forecast may not reflect a full market response to congressional action to tighten the timeframe for projects to qualify for the Section 45V Clean Hydrogen Production Credit. The credit is now only available for facilities that begin construction by the end of 2027 instead of 2032.

The operation of planned electrolyzers is also difficult to forecast, but they are unlikely to fully contribute to peak load for two reasons:

- The tax credit depends on the carbon-intensity of electricity consumption. This will drive electrolyzers operation to hours with high renewable generation, which are unlikely to be periods of peak net load.
- Regardless of the tax credit, electrolyzers will tend not to operate on-peak because the electricity would be too expensive.

SOURCE | U.S. EIA "Electrolyzers are a small but growing source of U.S. hydrogen production" (2024)

Load flexibility can reduce the capacity needed for large loads

Nearly all the preceding categories of large loads can use demand response, on-site generation and storage, or price-responsive loads to reduce or eliminate their contribution to peak demand.

The LTRA assessment of ERCOT's planning reserve margin assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%. Through 2035, as load grows by 59 GW, demand response grows by 50 GW. NERC states that it made this assumption because "signed into law in June 2025, Texas Senate Bill 6 directs the Public Utility Commission of Texas to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT's authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations."

While there is considerable debate about the feasibility for some types of data centers to provide flexibility, ERCOT's requirement shows the potential impact on resource adequacy. Nonetheless, no other load forecasts used to inform the LTRA include similar load flexibility assumptions. As a result, a large share of the projected load growth in the LTRA for other regions could be negated if NERC likewise assumed, as it did for ERCOT, that large loads use some type of flexibility during peak periods. Large loads in these regions could use similar flexibility solutions. For example, Google has signed agreements with utilities to use flexibility to reduce peak load contributions from data centers in Indiana, Nebraska, Arkansas, and the Tennessee Valley Authority footprint (Google 2025).

A recent study estimates 30% of data centers may install flexible capability anyway to curtail during localized transmission system overload or contingency events, as a way to move to the front of lengthy interconnection backlogs by reducing the need for cost- and time-intensive grid upgrades (Thomas 2026). Data centers that are unable to curtail could use behind-the-meter resources during peak periods to reduce or eliminate their reliance on grid power.

SOURCE | Google "How we're making data centers more flexible to benefit power grids" (Aug. 2025); Thomas, M. "Bypassing the Grid: How Data Centers Are Building Their Own Power Plants" (Feb. 2026)

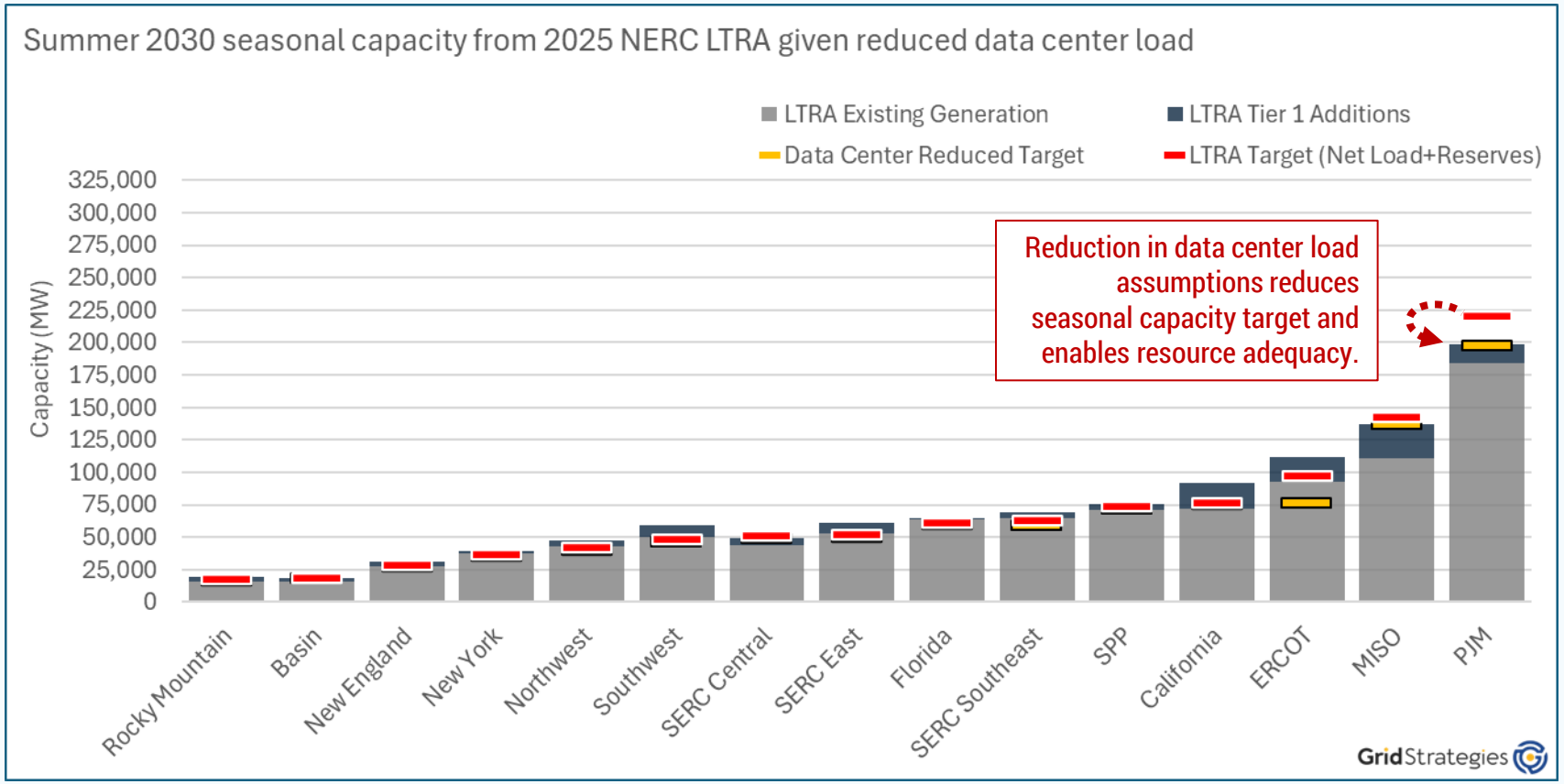
Updating data center load forecasts based on chip-industry forecasts would allow nearly all regions to meet their 2030 target needs

NERC indicates that load growth in several regions is dominated by data centers. To highlight the impacts of uncertainty in data center growth projections in the LTRA, we introduce a scenario which reduces national 2030 data center growth by two-thirds. This reduction is distributed among the regions based on their individual forecasted data center load and is shown as a yellow target in the chart.

A one-third reduction is based on chip industry forecasts and an additional one-third is based on assumed use of on-site generation during peak demand.

Consideration of potential reductions in data center load growth enables all regions to meet their 2030 peak summer load and reserve needs.

Note: If no red target is visible, then the two targets appear to overlap. All regions' net load was reduced.



GridStrategies

SOURCE | NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026)

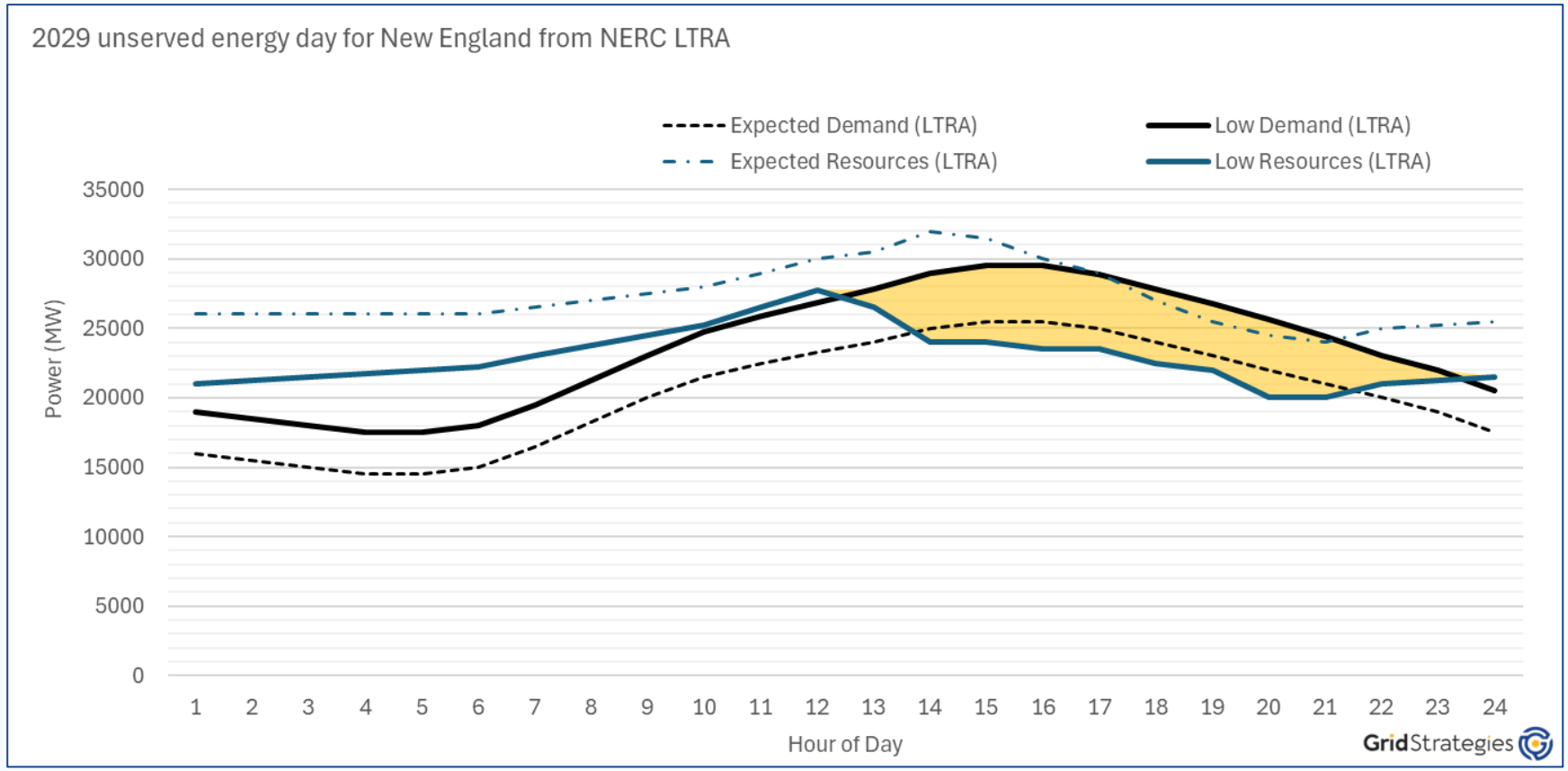
Extreme Event Energy Adequacy

Energy inadequacy risk during extreme events can exist even without seasonal capacity shortfalls. An increase in resource and interregional transfer capability also helps to alleviate extreme event risk.

The risk of energy shortfalls during extreme grid events can exist even without there being a risk of capacity shortfalls when considering only seasonal peak load. It is important to study both capacity and energy adequacy.

For example, NERC found energy shortfalls could occur during extreme heat days in New England,* even though it did not find seasonal capacity shortfalls.

Expected resource production is enough to meet expected demand (dotted lines) on most days, but sensitivity testing shows that the combination of lower-than-expected resources and high demand (solid lines) could result in energy shortfalls (yellow area). Energy shortfalls are often referred to as "unserved energy" or energy inadequacy.



*This figure is a recreation of the extreme event energy analysis shown in the LTRA for New England. We did not independently reproduce this analysis.

GridStrategies

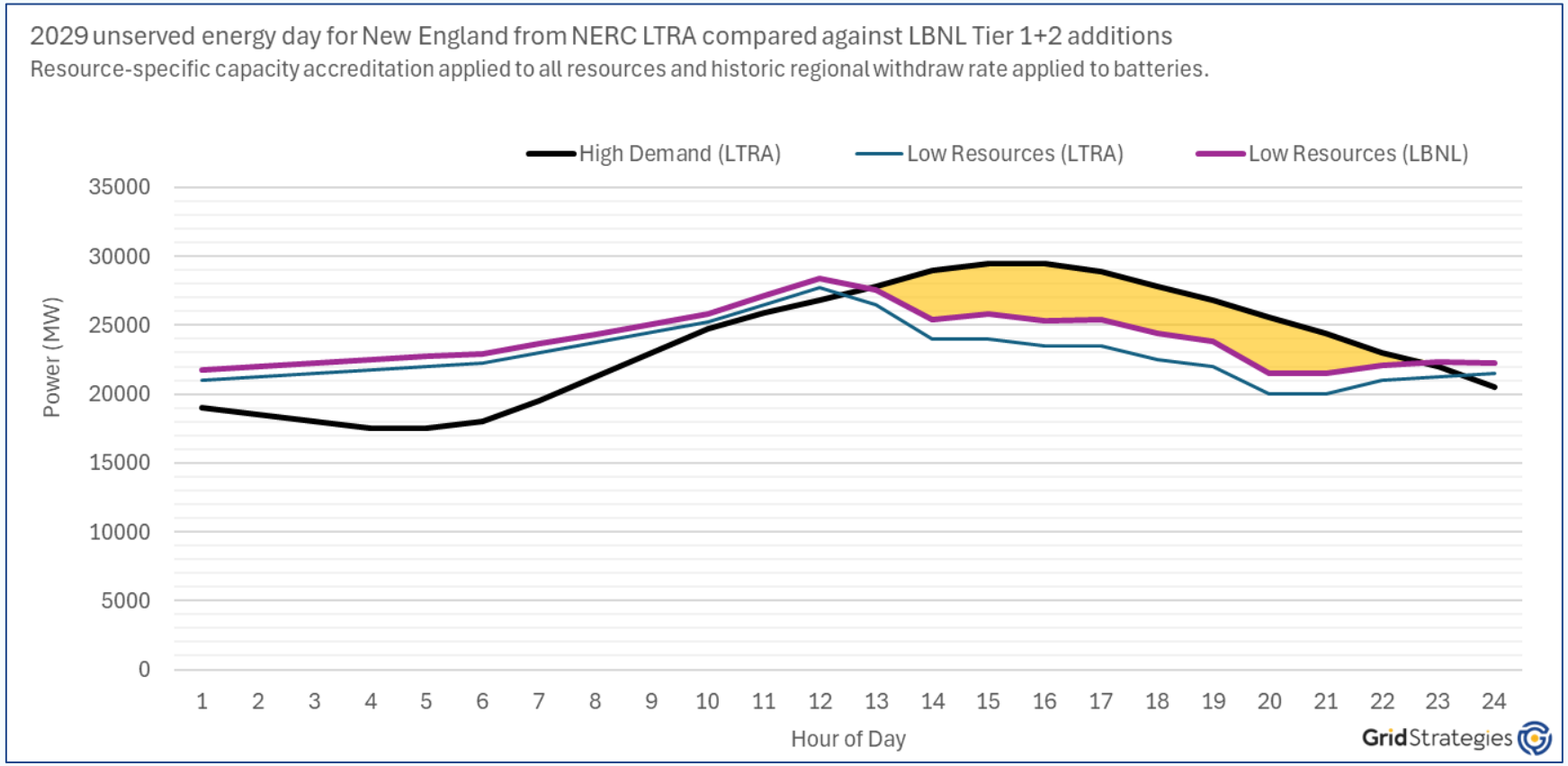
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Using LBNL resource assumptions for New England greatly reduces unserved energy risk during peak load days.

LBNL data records more solar, offshore wind, and storage resources than the NERC data.* Lower-than expected production from the LBNL-identified resource mix (purple line) better matches the times of high demand (black) than the NERC-identified resource mix (blue).

Given accredited, likely-to-connect Tier 1 and 2 resource capacity from LBNL, the amount of potential unserved energy on peak summer days in New England is reduced by nearly 40% of that calculated using NERC data. If capacity had not been reduced by expected withdrawals, the unserved energy shown here would be completely resolved.

Diverse resource mixes—especially those matched to the load profiles of the region—provide major benefits to withstand extreme grid events.



*See the Methodology section for more details.

GridStrategies

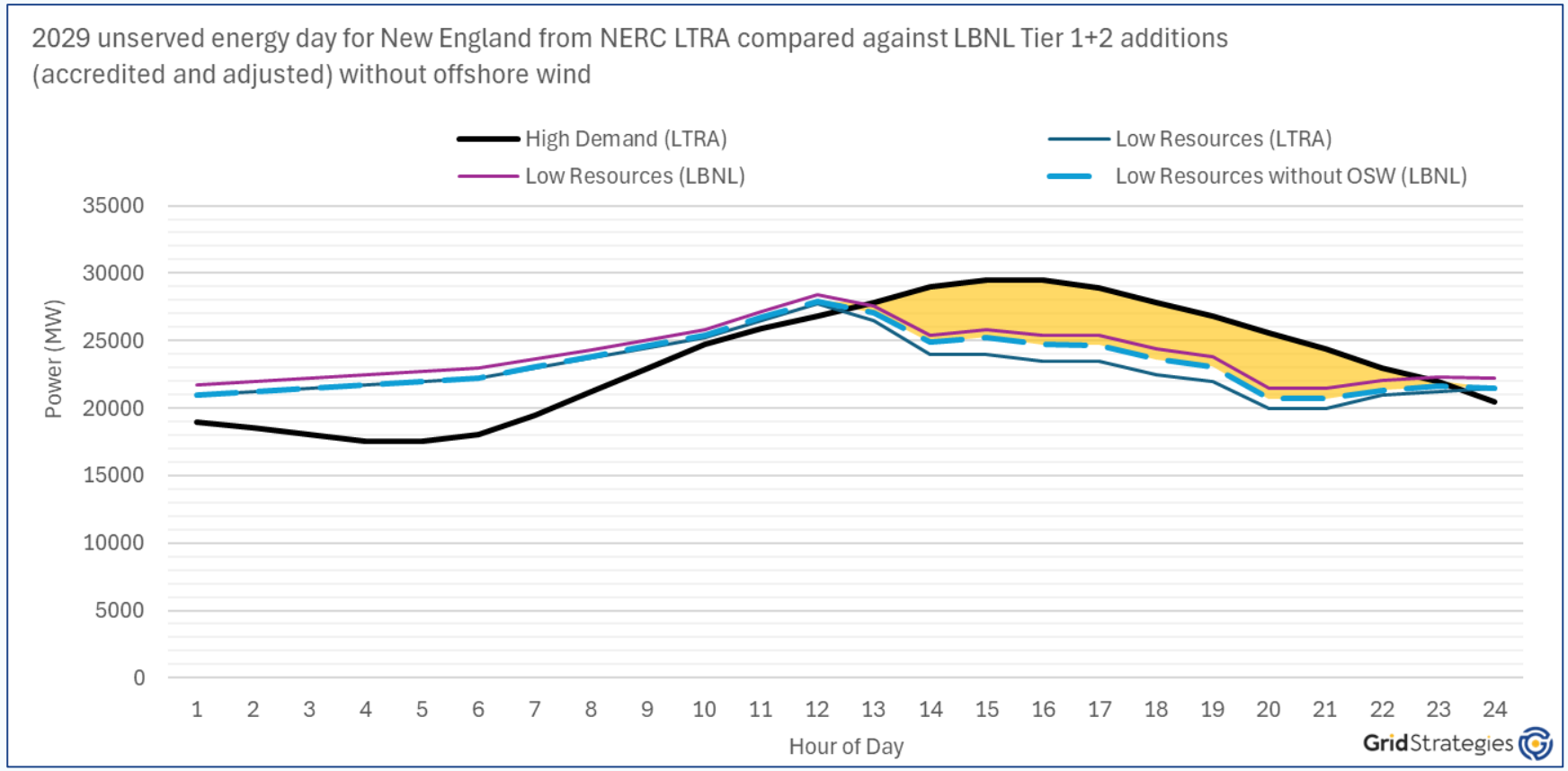
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

As with seasonal capacity adequacy, permitting and/or construction delays of resources with executed IAs are likely to exacerbate energy inadequacy risk during extreme grid events.

Delays of resources progressing through the queues or with executed IAs, whatever the cause, will exacerbate the risk of unserved energy during extreme grid events. Currently, offshore wind is facing additional permitting and construction hurdles. This is especially noteworthy for New England, where strong afternoon offshore wind output could directly reduce unserved energy risk during peak load hours.

Near-term unserved energy risk increases substantially given the delay or cancellation of planned offshore wind generation.

Given the low production of a resource mix without offshore wind (shown as the blue dotted line), the unserved energy risk is only reduced by 20% instead of 40% of that calculated in the LTRA.



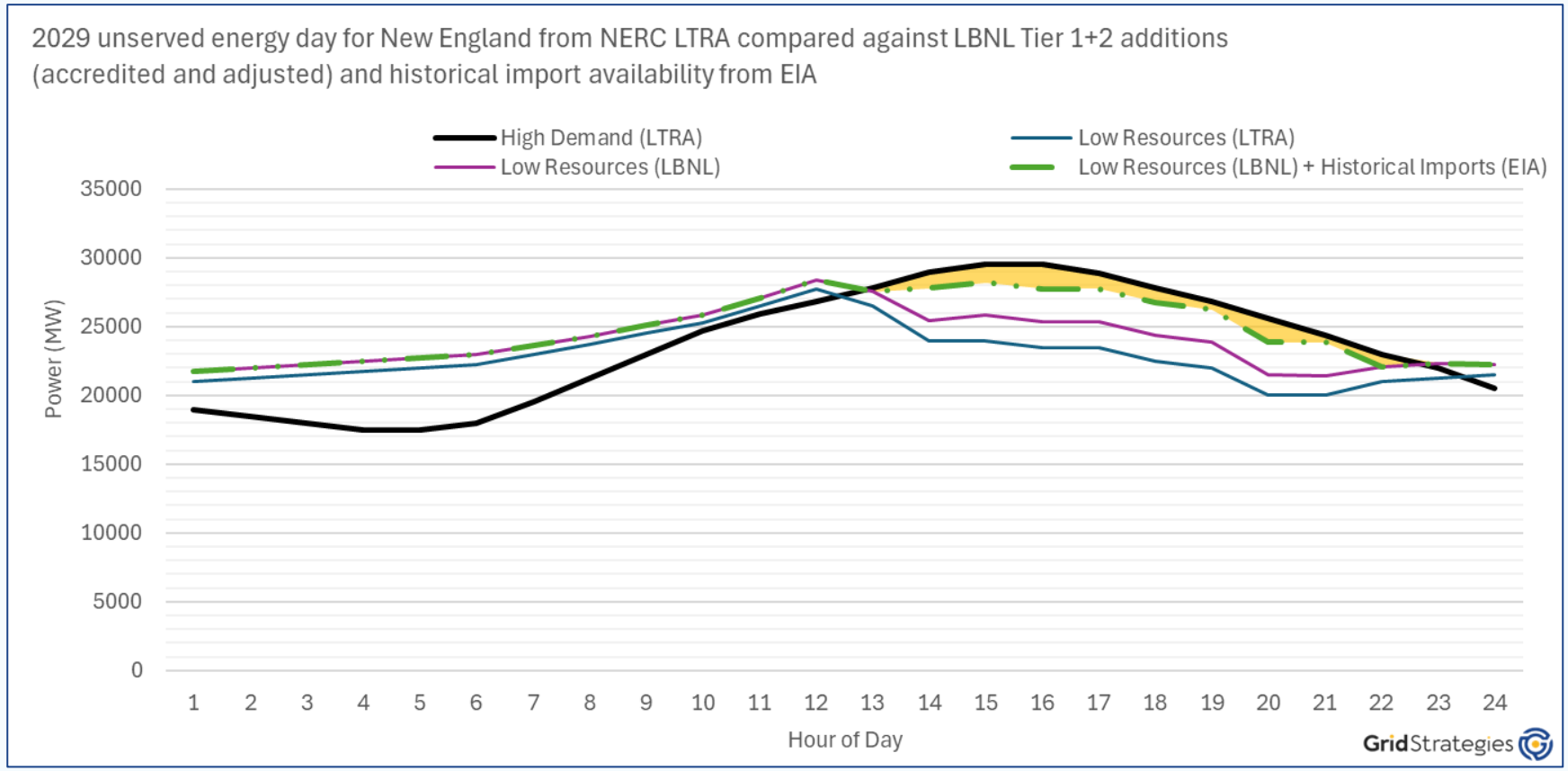
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Interregional transmission designed to move power between regions during times of grid stress further reduces unserved energy risk.

As explained in slides 15-17, NERC only includes firm imports in its seasonal capacity or energy adequacy analysis. This ignores the likelihood of additional "non-firm" imports which are historically available to regions during extreme events. Non-firm imports are those which are not contracted for use during normal operations, but that neighboring regions can export to regions experiencing heightened stress.

Adding the imports which have been historically available to New England during extreme events further reduces expected unserved energy.

The combination of likely-to-connect generation from the interconnection queues and historically available non-firm import data nearly eliminates the unserved energy risk calculated using the LTRA assumptions.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

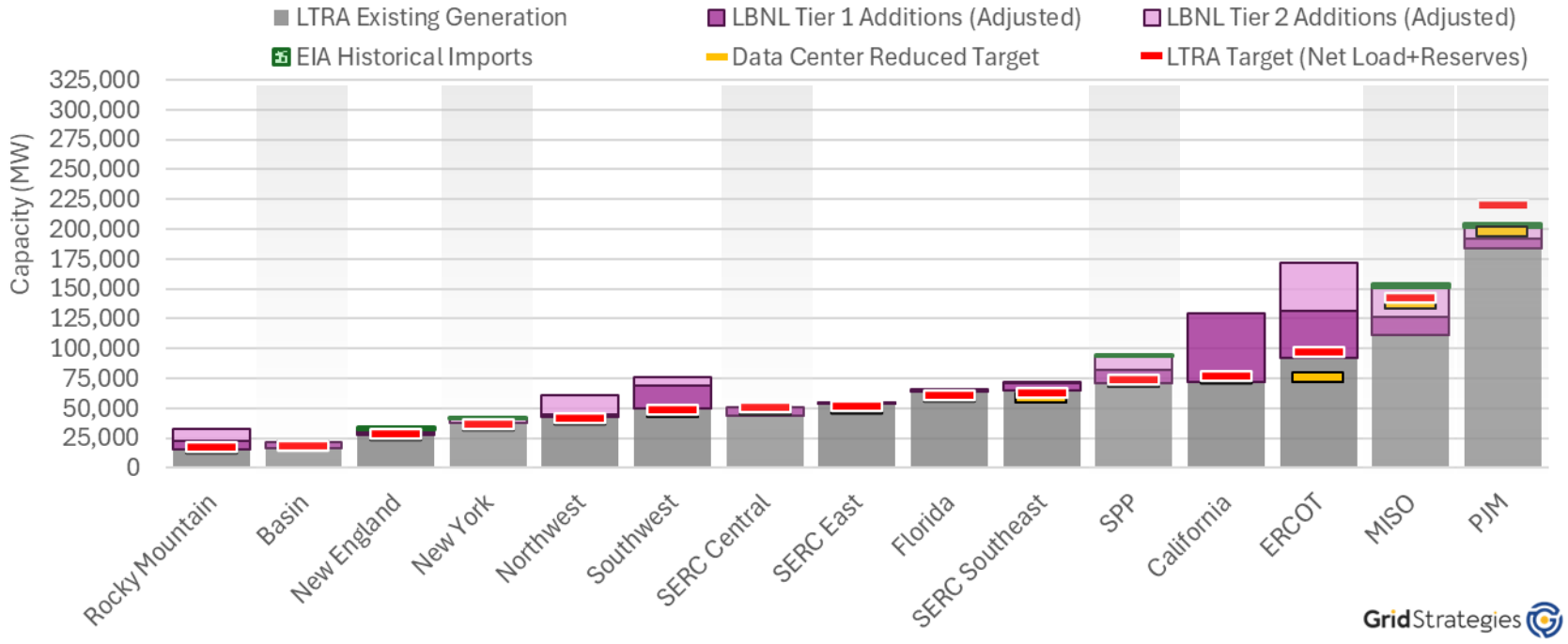
Conclusions and Solutions

In this analysis, we considered different assumptions for generation resource, interregional transmission, and demand than the LTRA. The combination of all three suggest all regions could be resource adequate.

The regional seasonal resource adequacy risks identified in the 2025 NERC LTRA are all resolved when evaluated under different input assumptions:

- Including generation that is actively working through the interconnection queues in each region (Tiers 1 & 2)
  - Discounting all generation nameplate capacity by the resource and region-specific accreditation methods
  - Discounting generation queue data by historic regional and phase-specific withdraw rates
- Consideration of historic non-firm imports during extreme events
  - Including increased interregional transfer capability capacity (albeit low likelihood of 2030 in-service date)
- Reduced data center load to account for microchip industry supply chain constraints and generation flexibility

Summer 2030 seasonal capacity with queue additions from LBNL database (adjusted for expected withdrawals), interregional import capacity (adjusted for historical imports), and reduced data center load



GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

While reduced risk is likely given different assumptions, these results should not be taken for granted. Enacting existing solutions is needed to stave off future reliability risk.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Methodology

The NERC LTRA assesses each region's ability to meet both its future capacity and energy adequacy needs.

NERC's LTRA importantly captures potential reliability issues for a snapshot in time. Risk is defined by tightening reserve margins—the difference between electricity demand and available supply.

In its 2025 version, NERC identified several regions* as either **High** or **Elevated** risk of not being able to meet their future capacity and energy needs.

Seasonal capacity shortfall risk: MISO, PJM, and SERC-Central (with SPP and Basin on the margin)

Extreme event energy shortfall risk: MISO, PJM, New England, New York, SERC-East, Basin, Northwest, and ERCOT

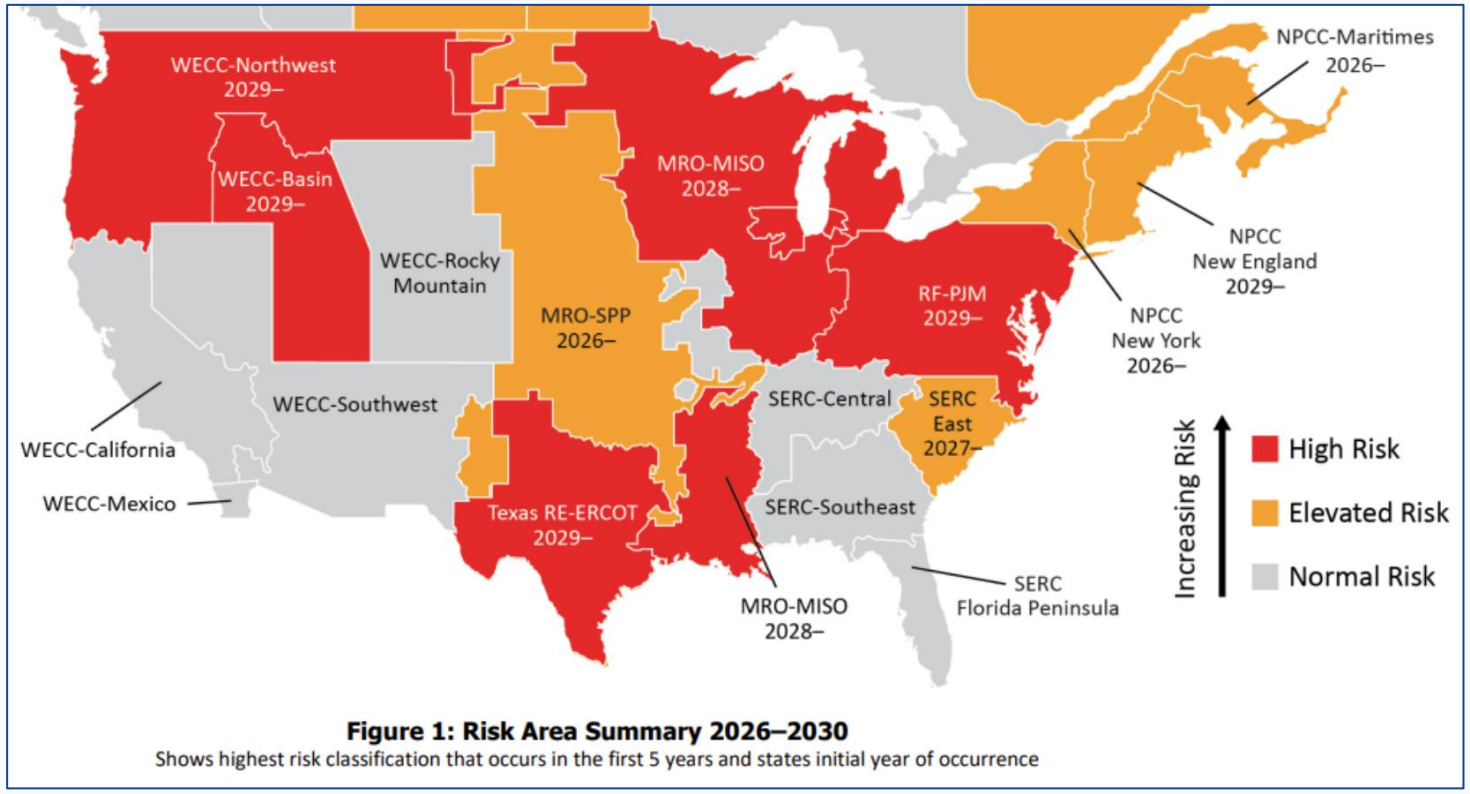


Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

*NERC did not mark SERC-Central as elevated risk despite showing large seasonal shortfalls while SPP was marked as elevated risk despite having neither seasonal capacity shortalls nor extreme event energy shortfalls.

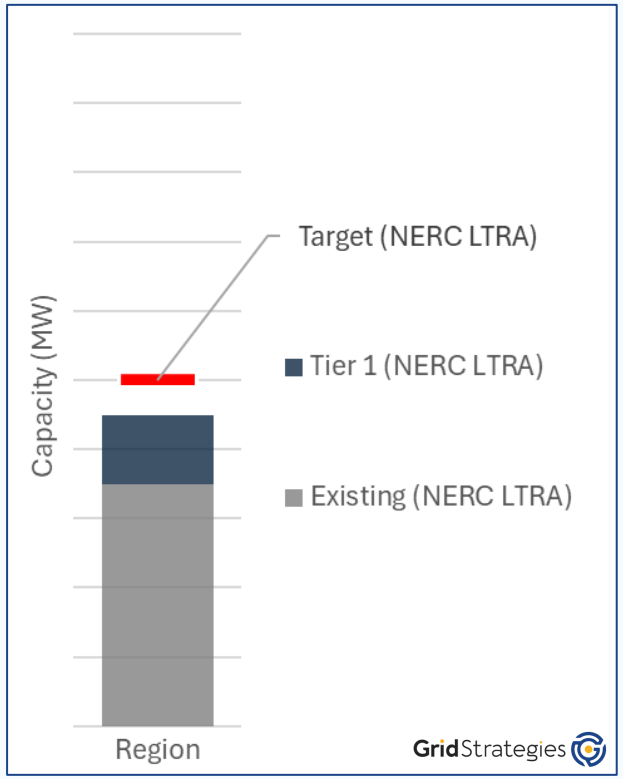
GridStrategies

SOURCE | NERC "2025 LTRA" (2026)

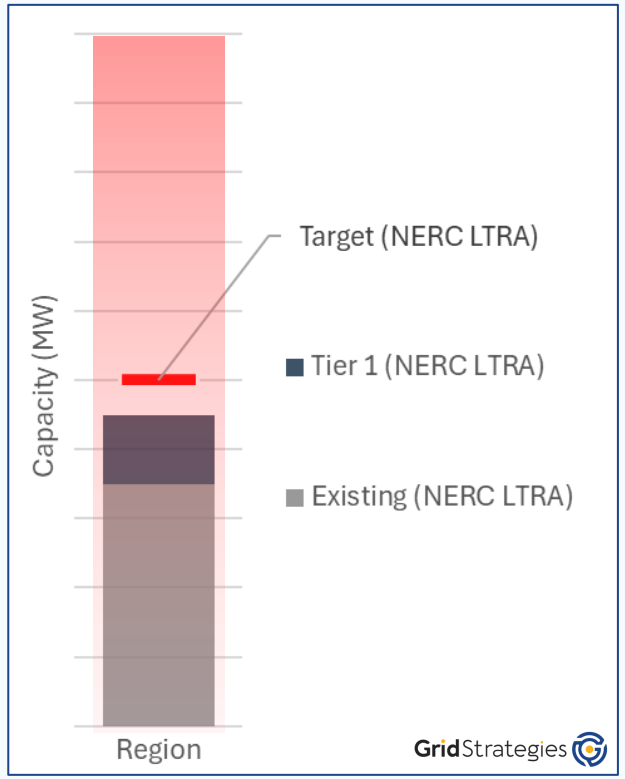
Illustrative walkthrough of seasonal capacity slides

Bar charts showing the existing (light grey) and future (dark blue) resource capacity in each region using NERC LTRA data. The target capacity (red line) is also shown. These charts were created by Grid Strategies using NERC data.

A red highlight is used to signify a shortfall between the existing + future resource capacity and the needed target to meet future load and reserves. A yellow highlight would be used to signify a "near miss."



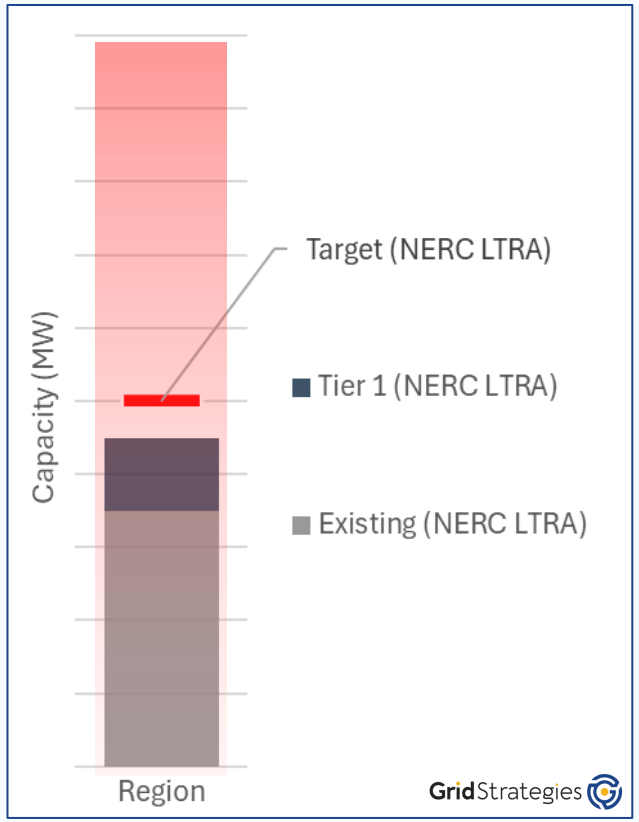
Highlight important features of chart



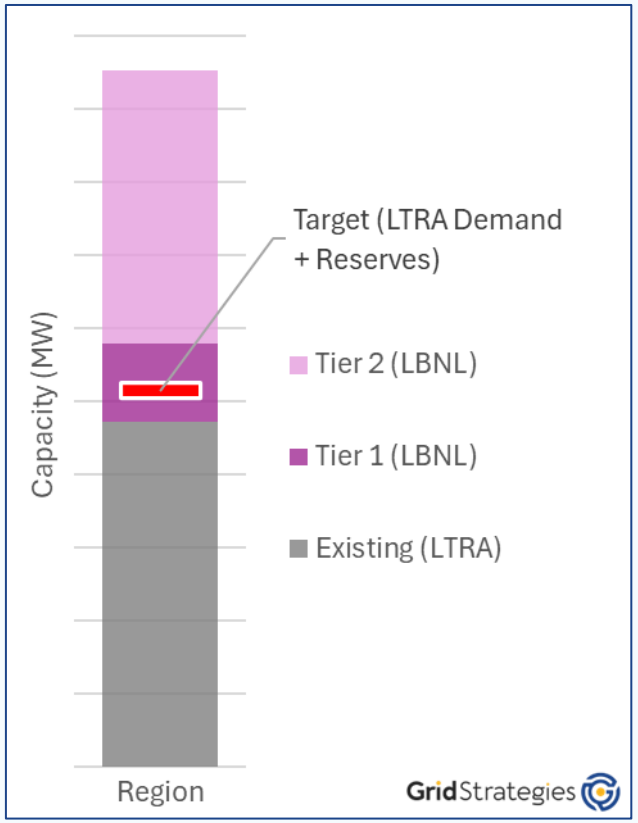
Illustrative walkthrough of seasonal capacity slides

Replace the NERC LTRA resource capacity data with accredited LBNL interconnection queue data (purple) for comparison. Existing and target data is from LTRA and remains unchanged unless specified.

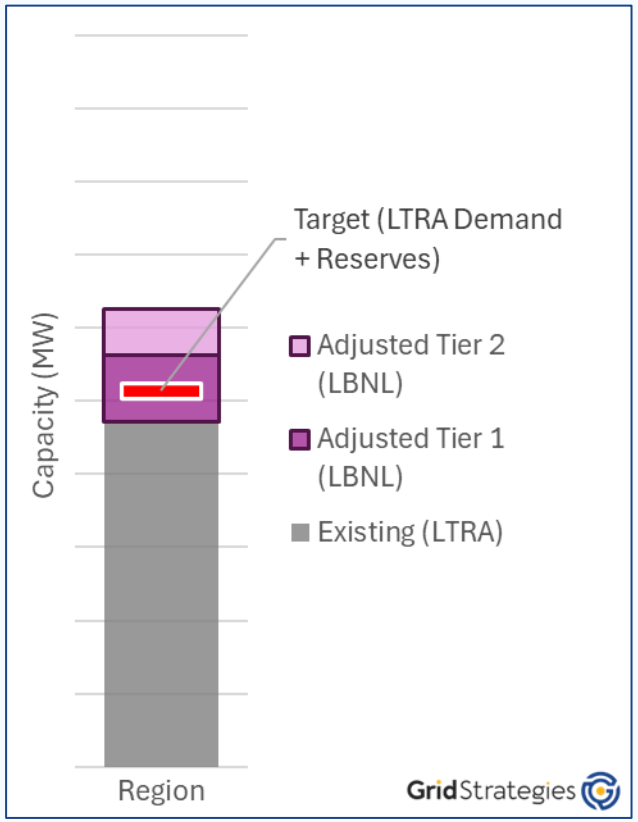
To avoid overcounting queue generation, the LBNL data is discounted based on regional- and study phase-specific withdraw rates.



Replace NERC data with resource-accredited LBNL data



Reduce LBNL data based on expected withdraws



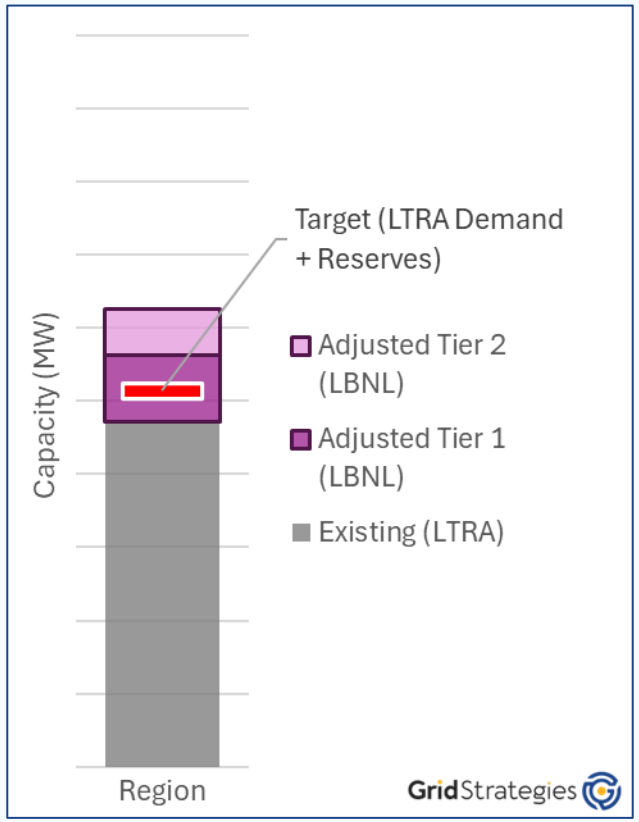
Note red highlight is removed because adequacy has been achieved

GridStrategies

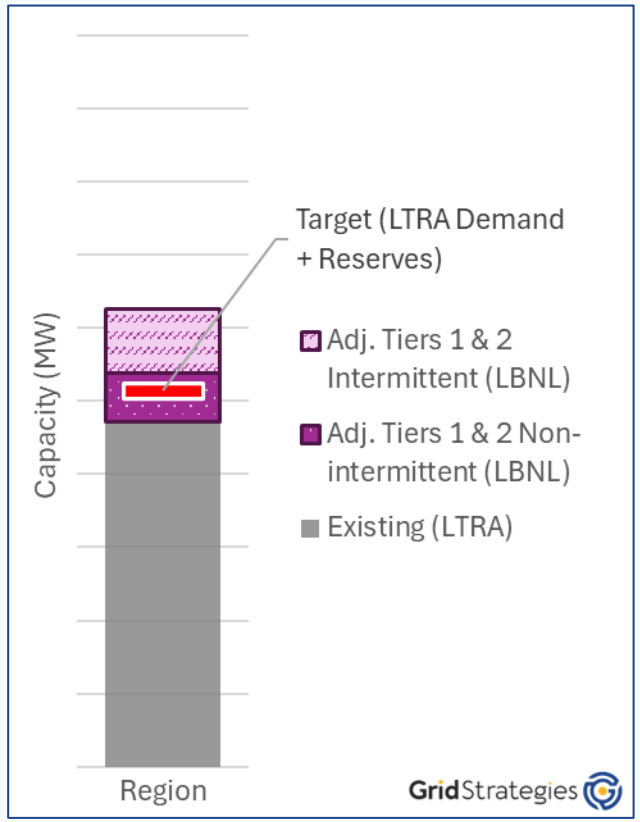
Illustrative walkthrough of seasonal capacity slides

Analyze the LBNL resource data to gain insight into future capacity risk. Purple is still used for LBNL data while different bar borders or pattern are used to indicate interesting features of the data.

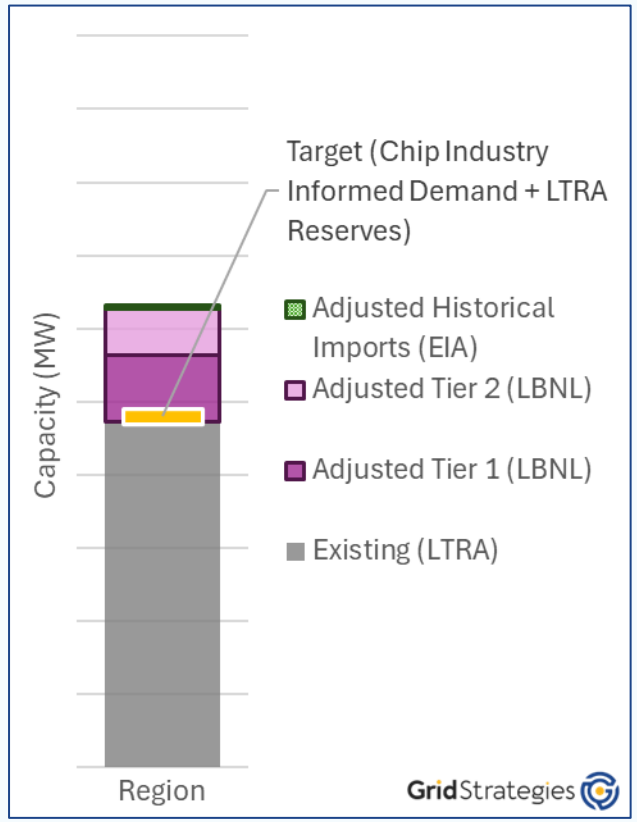
Interregional transfer capability data is adjusted using EIA data to better illustrate available capacity. In some cases, the expected load is changed to match demand forecasts from other sources.



Look at different features of LBNL data



Continue to add more data for analysis



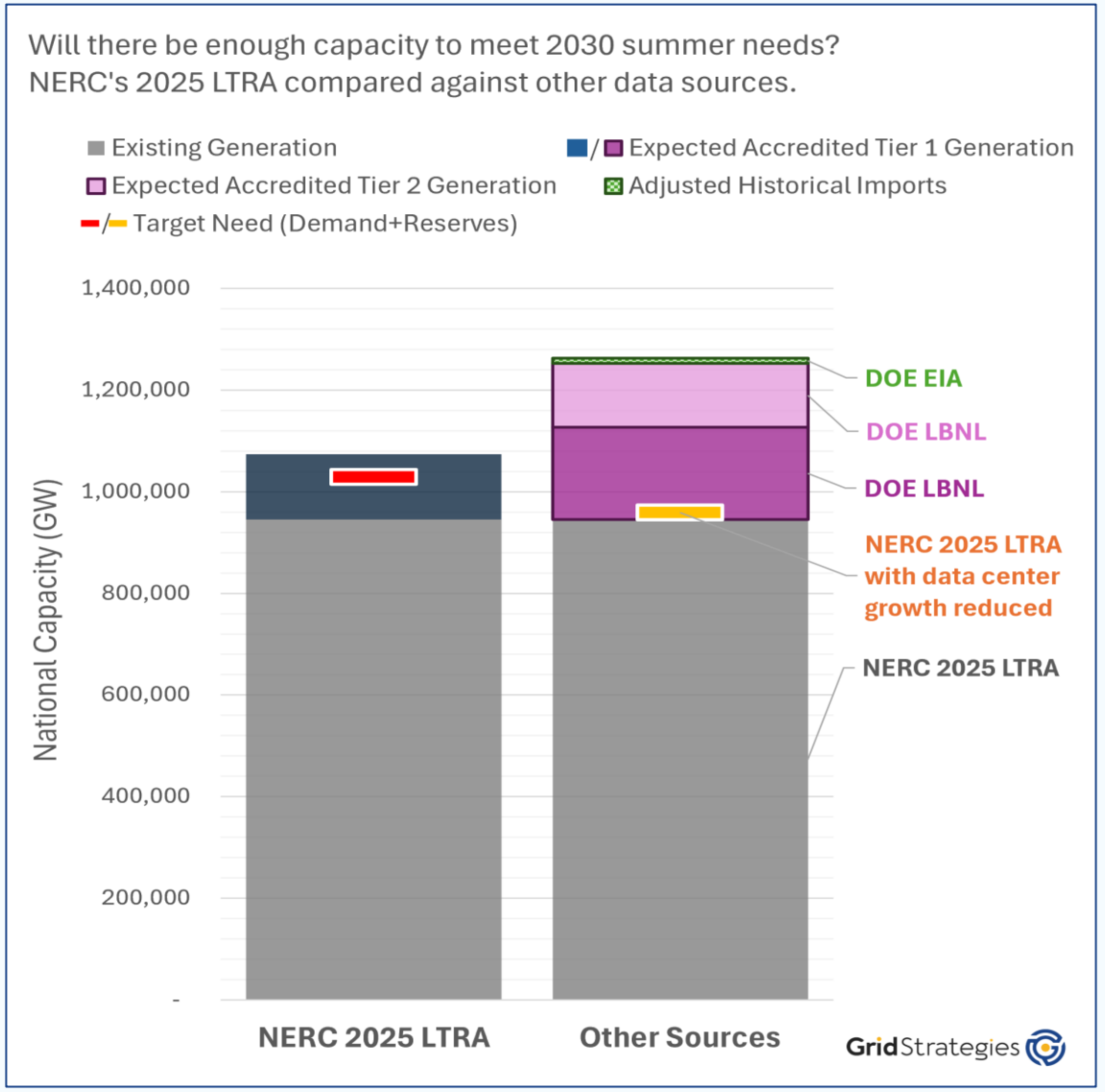
Summary slide of seasonal capacity differences in 2030

On Slide 6, the comparison of NERC 2025 LTRA analysis against our analysis using other sources is meant as an illustrative comparison of the national risk given the use of different credible data sources.

The NERC 2025 LTRA bar was made by summing the forecasted 2030 summer load + reserves (target), existing generation, and Tier 1 data for each region directly from the NERC data.

The target value shown in "Other Sources" was created by applying a one third derate to known data center load growth in all regions. The one-third derate factor is the ratio of estimated data center growth in 2030 from chip shipments to the estimated growth from utility roll-ups as used by LTRA (Wilson, J., et al. 2025). Another one-third derate factor is from the assumption that many data centers are likely to use some form of on-site generation or storage to curtail their peak demand (Thomas, M., 2026). The known data center load growth is from Grid Strategies analysis of total system load growth that is attributable to data centers (Wilson, J., et al. 2025). The impact of this data center growth reduction scenario on individual regions is shown in slide 24.

The generation resources shown in "Other Sources" is the sum of resources available in the LBNL dataset that are reasonably expected to connect by 2030. Adjusted historical imports represent the non-firm imports that have been available during grid stress events from the Energy Information Administration. More detail on the other sources data is provided in subsequent slides.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026); Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Analysis using LBNL data: Regional assessment areas

The DOE's Lawrence Berkeley National Laboratory collects data from the generation interconnection queues for seven ISOs / RTOs and 49 non-ISO balancing areas (including utilities and Power Marketing Administrations), representing roughly 97% of currently installed U.S. generating capacity. This data is compiled annually with help from Interconnection.fyi and is posted for public view at emp.lbl.gov/queues. The 2025 dataset includes data through the end of 2024.

The 56 entities in the LBNL database were mapped to the NERC LTRA assessment areas by geography (maps to the right). The non-RTO utilities were mapped as follows:

WECC California
- LADWP
- SMUD
- WAPA-SN

WECC Rocky Mtn
- CLPT
- BHCT
- CSU
- PacifiCorp
- PRPA
- PSCo
- TSGT
- WAPA-RM

WECC Northwest
- Avista
- BHP
- BPA
- CPUD
- GrantPUD
- MPC
- NWMT
- PGE
- PSE
- TPU
- WAPA-IS

WECC Basin
- IdahoPower

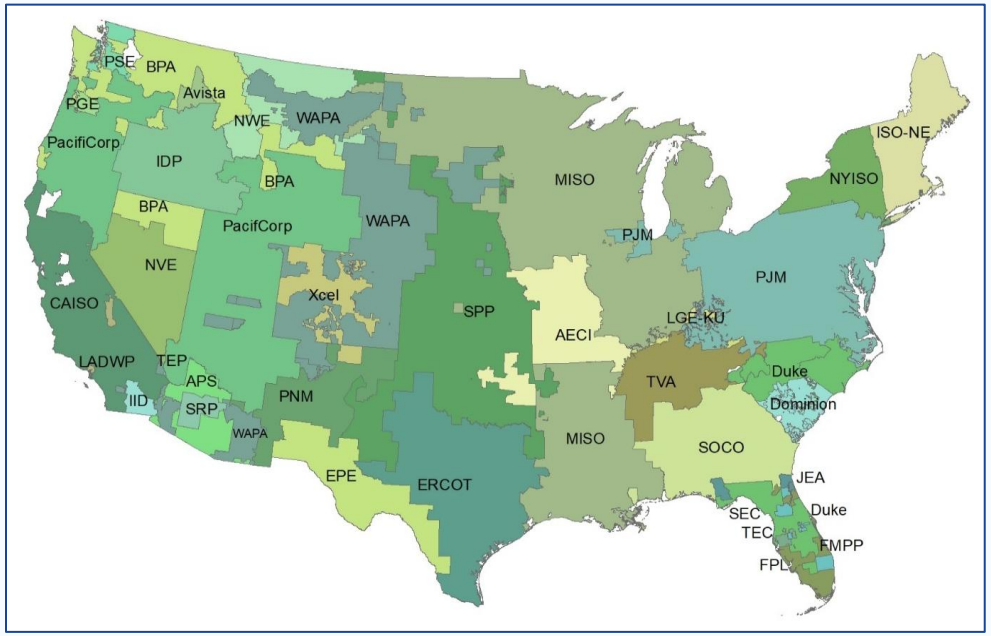
WECC Southwest
- APS
- EPE
- IID
- N-C
- NVE
- PNM
- SRP_ANPP
- SRP
- SRP_Gila
- SRP_PV-PC
- SRP_SWV
- TEP
- WAPA-DSW
- WAPA-MPP

SERC Central
- AEC
- LGE-KU
- TVA

SERC Southeast
- GTC
- SOCO

SERC Florida
- OUC
- TEC
- Duke (FL)

SERC East
- Dominion
- S-C
- Duke (non-FL)



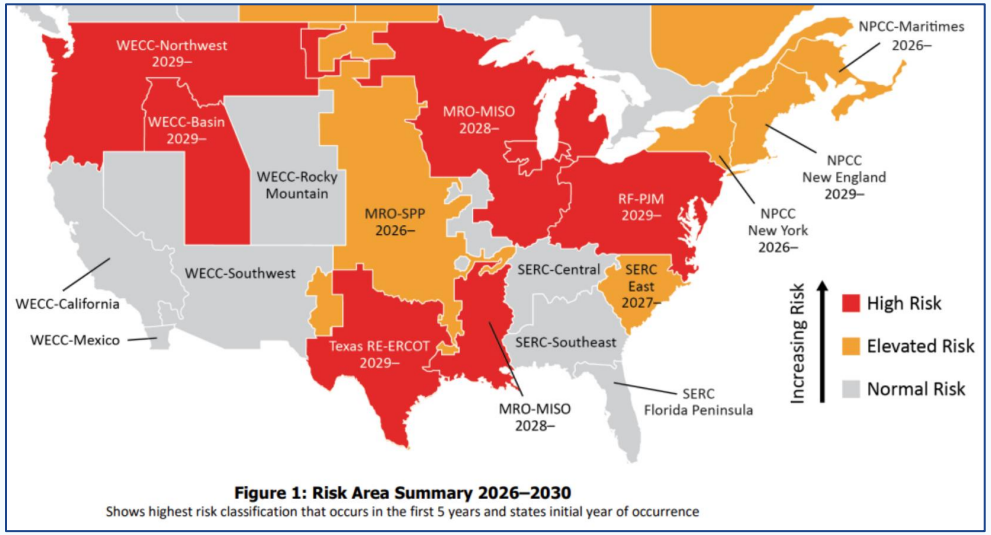


Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis of LBNL data: Generation tier status

LBNL interconnection data is organized by its queue status and study phase in the interconnection queues. Queue status refers to if the facility is completed, withdrawn, or actively progressing through the queues.

NERC organizes in-development generation resources by Tiers, where:

- Tier 1 are resources with executed interconnection agreements
- Tier 2 are any resource that is in the study process, and
- Tier 3 are those that have submitted interconnection requests but are not yet under study.

The cross-walk between LBNL's "Queue Status" and "IA Status Clean" fields and the NERC Tiers used in this analysis are shown to the right. Interconnection requests marked as Active in the Queue Status are organized into Tiers based on their IA Status.

Resources considered in to be in advanced Tier 2 status were those with either "IA Pending" or "Facility Study" status in the LBNL data. Suspended interconnection requests are considered Tier 2 because they have already completed some study phases but have paused their continuation of progress. Requests that un-pause often enter at the same study stage. Requests of Unknown or N/A status are considered Tier 3 because their existence in the database indicates an interconnection request has been made, but whether studies have begun cannot be said for sure.

LBNL Queue Status	NERC Tier
Active	(see IA Status)
Withdrawn	Cancelled
Operational	Operational
Suspended	Tier 2
Unknown	Tier 3

LBNL IA Status Clean	NERC Tier
Withdrawn	Cancelled
Operational	Operational
IA Executed	Tier 1
Construction	Tier 1
IA Pending	Tier 2
Facility Study	Tier 2
Cluster Study	Tier 2
System Impact Study	Tier 2
Feasibility Study	Tier 2
Combined	Tier 2
In Progress (unknown study)	Tier 2
Suspended	Tier 2
Not Started	Tier 3
N/A	Tier 3

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Expected withdraw rates

To reduce the likelihood of overcounting generation resources that may not interconnect, we reduced all Tier 1 and 2 resource data in the LBNL queue dataset given region- and status-specific historic withdraw rates.

LBNL publishes the completion rates (as of 2024) of all resources in the regional queues that entered the queue between 2000 and 2019. The withdraw rates vary regionally between 64% and 85%. LBNL also provides information about the queue study phase that projects were in when they withdrew. In general, fewer projects withdraw once they reach advanced stages of the interconnection queue process.

Applying the regional withdraw rates to all generation without regard for its queue location would overly discount generation in Tier 1 and advanced Tier 2 status. Instead, we adjust the amount of generation that is expected to withdraw from each Tier separately. See illustrative figure to the bottom right.

We first calculate the total amount of expected regional withdraws by applying the appropriate withdraw rate to the sum of all Tiers 1, 2, and 3 generation in each region's queue. We assume that 15% of generation in Tier 1 status will withdraw, equivalent to the share of withdrawn requests between 2019 – 2023 in the IA executed phase from LBNL's analysis. Because no generation in Tier 3 is expected to interconnect by 2030, we assume 100% of Tier 3 generation withdraws for every region. The difference between the total amount of expected regional withdraws and that which is assumed to withdraw from Tiers 1 and 3 in each region is applied to the Tier 2 data.

LBNL: Historical completion by region for requests submitted 2000-2019 (as of 2024)

Region	Active	Operational	Withdrawn
CAISO	14%	9%	77%
ERCOT	14%	22%	64%
ISO-NE	8%	18%	74%
MISO	9%	15%	76%
NYISO	7%	8%	85%
PJM	8%	14%	77%
SPP	9%	14%	76%
Southeast	5%	9%	85%
West	13%	9%	79%

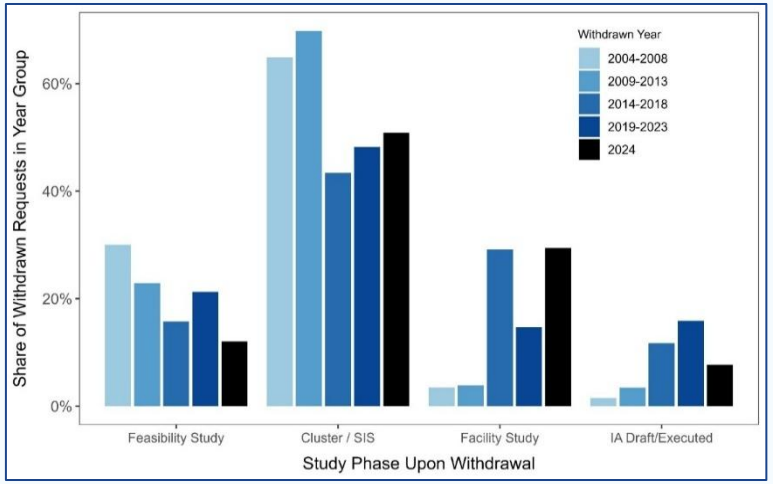
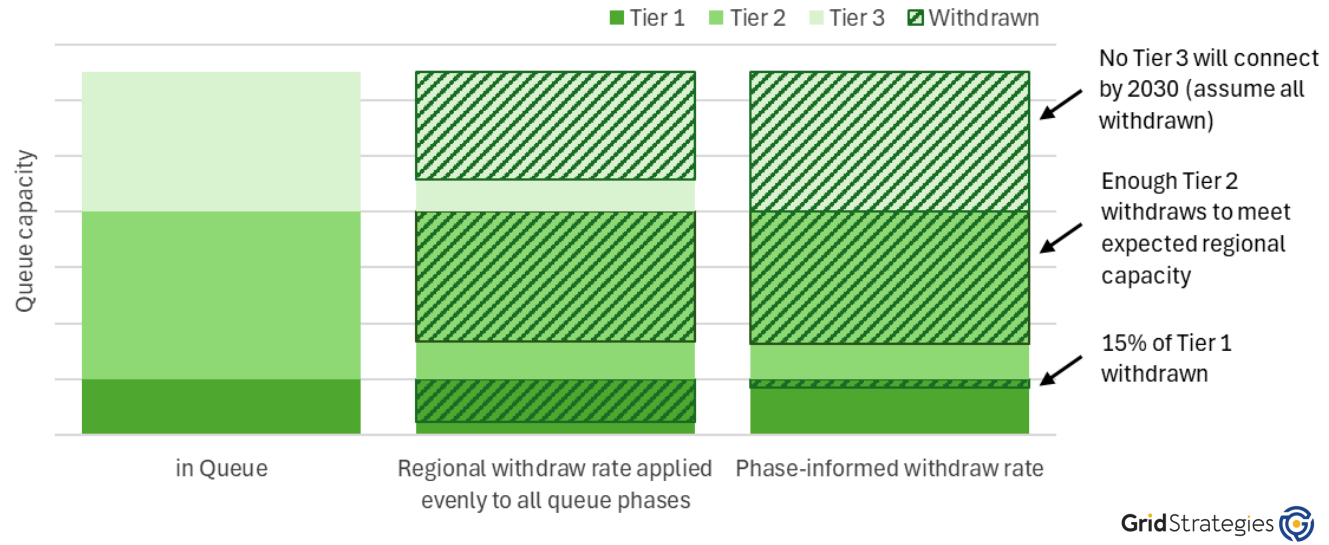


Illustration of two different methods to apply regional withdraw rates to interconnection queue data. The same amount of generation capacity withdraws in both methods.



GridStrategies

SOURCE | Rand, J., et al. (2025)

Analysis using LBNL data: Resource type

LBNL interconnection data is organized by generation resource type. When multiple resource types (e.g., gas and battery storage) are combined into one interconnection request, LBNL lists each resource type. The LBNL database includes a "type_clean" field, which summarizes all types of resources included in the interconnection entry.

These "clean" resource types are organized into a fewer number of categories in our analysis for simplicity. The cross-walk is provided in the two tables to the right.

LBNL Clean Type	Resource Type
Battery	Battery
Offshore Wind+Battery	Battery Hybrid
Other+Battery	Battery Hybrid
Solar+Battery	Battery Hybrid
Solar+Other+Battery	Battery Hybrid
Solar+Wind+Battery	Battery Hybrid
Wind+Battery	Battery Hybrid
Geothermal	Geothermal
Solar+Other	Hybrid
Solar+Wind	Hybrid
Wind+Other	Hybrid
Hydro	Hydro
Offshore Wind	Offshore Wind
Other	Other
Hydrogen	Other Storage
Other Storage	Other Storage
Solar	Solar
Battery+Other Storage	Storage Hybrid
Other+Battery+Other Storage	Storage Hybrid
Solar+Battery+Other Storage	Storage Hybrid
Solar+Wind+Other Storage	Storage Hybrid
Wind	Wind

LBNL Clean Type	Resource Type
Coal	Coal
Gas+Battery	Firm Hybrid
Gas+Battery+Diesel	Firm Hybrid
Gas+Coal	Firm Hybrid
Gas+Diesel	Firm Hybrid
Gas+Oil	Firm Hybrid
Gas+Other	Firm Hybrid
Geothermal+Battery	Firm Hybrid
Hydro+Battery	Firm Hybrid
Oil+Battery	Firm Hybrid
Oil+Coal	Firm Hybrid
Oil+Other	Firm Hybrid
Other+Coal	Firm Hybrid
Other+Diesel	Firm Hybrid
Solar+Diesel	Firm Hybrid
Solar+Gas	Firm Hybrid
Solar+Gas+Battery	Firm Hybrid
Solar+Geothermal	Firm Hybrid
Solar+Hydro	Firm Hybrid
Wind+Gas	Firm Hybrid
Gas	Gas
Diesel	Oil
Oil	Oil
Nuclear	Nuclear

GridStrategies

SOURCE | NERC "ES&D" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Accredited capacity

No resource will produce electricity at its rated capacity ("nameplate") all the time. To account for this, regions apply an accredited value to a resource to indicate a percentage of the nameplate capacity that can be expected to perform during peak demand. The accredited value of a resource varies by fuel type, season, year, and geographic location.

Each region calculates accredited capacity differently. Some consider historic forced outages of a resource type (which tend to overestimate availability) while others use modeling tools to determine how much load a resource can be expected to carry in future years given numerous system dynamics.

The LBNL interconnection queue database provides nameplate values for all generators in the queues. To ensure only a reasonable amount of new resources are accounted for in our analysis, we seasonally accredit each resource type based on the region-specific method used locally for resource accreditation. If a region does not use seasonal or resource-specific accreditation, a neighboring region's method is used.

Unless otherwise noted:

- Battery Hybrid resources are equivalent to battery resources' accredited values
- Firm Hybrid resources are the average of firm resources' accredited values
- Hybrid resources are the average of wind and solar resources' accredited values
- Other resources are the average of any remaining resources' accredited values not otherwise listed

Region	Accreditation Method & Source	Notes
MISO	2025-2026 DLOL	Summer & winter values. Battery resource uses storage (blended) and storage hybrid uses pumped storage DLOL. MISO values are also used for all other regions' resources that are not otherwise noted.
SPP	ELCC for Summer 2026	Summer values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	ELCC for Winter 24/25	Winter values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	25/26 EFORd	Summer & winter values used for all non variable resources. Oil and other resources are RICE with on-site storage, gas is CC. Values also used for ERCOT other; WECC summer other storage.
ISO-NE	CAR-SA: Impact Analysis 1/14/26	Summer & winter values. Used for solar, wind, and hydro resources
ISO-NE	2025 Capacity, Energy, Loads, and Transmission (CELT) Report	Summer & winter values. CELT used for battery, battery hybrid, coal, gas, nuclear, offshore wind, oil, other, and other (pumped) storage resources.
NYISO	2025-2026 Final Capacity Accreditation Factors	Summer values used for both seasons. Rest of state values used for battery (6-hour), hydro, offshore wind, other, other storage (pumped storage), solar, wind.
NYISO	2024 Review of EFORd	Summer & winter values. NYCA values used for coal (steam turbine), gas (CC), nuclear (steam turbine), oil (jet engine). NYISO values are also used for SERC-E summer battery and summer wind.
PJM	2027/2028 ELCC Class Ratings	Summer values used for both seasons for all resources. Battery is 6-hour CSR, battery hybrid is configuration 3, gas is CC, other is waste-to-energy, other storage is other unlimited resources, solar is fixed-tilt, storage hybrid is configuration 1. PJM values also used for SERC-E hydro, nuclear, oil, other, and other storage resources.
ERCOT	25/29 CDR	Summer & winter values for battery (6-hr), other storage (12-hr), solar, and wind. Values also used for SERC-FP and SERC-SE battery.
SERC	2025 CRP Chapter 3	Winter values used for both seasons. 2030 Reference case used for battery (standalone BESS), battery hybrid (synergistic BESS), offshore wind (avg. ELCC for first 800MW), solar (avg. ELCC for first 10 GW of standalone), wind (avg. ELCC for DEP and DEC for first 300 MW).
SERC	2023 Wind ELCC Study	Average ELCC of 5GW and 15GW standalone solar used for all SERC regions' summer solar.
Southwest	E3 2023 Resource Adequacy in the Desert Southwest	2033 values also used for WECC regions' winter battery, summer hydro, summer nuclear, winter and summer wind (unless otherwise stated).
Northwest	E3 2025 Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results	Winter values for Greater Northwest used for WECC regions' gas, other storage, solar, wind (unless otherwise stated).
Northwest	E2 2019 Resource Adequacy in the Pacific Northwest	Winter values for 2030 Reference scenario used for WECC regions' coal, geothermal, hydro, nuclear (unless otherwise stated).
CAISO	2026 Net Qualifying Capacity (NQC) for RA Resources	Summer and winter values used for CAISO geothermal, hydro, other (biomass), solar, wind. Values also used for other WECC regions' other, solar, hydro and geothermal (unless otherwise stated).
National	NREL VRE ELCC Study	Median offshore wind used for SERC-FP (SERC), ERCOT, WECC-NW (NorthernGrid), CAISO

Adding historically available interregional transfer capability to the seasonal capability analysis

The EIA historical imports included in the charts on slides 16 and 29 take the difference between the historical import availability (2015 and 2025) from the U.S. EIA Form 930 data and the 2030 firm import assumptions in the LTRA. The last column subtracts imports from demand in all peak hours over the last decade and shows the minimum reduction in in-region generation due to imports.

For New York, an additional 1,250 MW of import availability was added to the EIA Form 930 data to account for the energization of the Champlain Hudson Power Express transmission line.

Comparison of on-peak net imports in four regions as assumed by LTRA against actual, in MW. Exports are negative.

	LTRA 2026 Assumption	LTRA 2030 Assumption	Historical Availability (2015-2025)
MISO	2,809	2,509	5,344
SPP	-18	-78	1,421
ISONE*	567	84	2,464
NYISO	3,405	3,486	2,730†
PJM	3,840	0	2,937‡

*Data for New England (ISONE) predates completion of the 1200 MW New England Clean Energy Connect with Hydro Quebec, so on-peak imports will likely be higher going forward.

† EIA data for New York does not include the Champlain Hudson Power Express, a 1,250 MW line connecting Quebec to New York City that is slated for completion in 2026. Once that is included, NYISO imports should be roughly in line with the LTRA.

‡ The EIA data show PJM was exporting during most peak demand periods over the last decade, so it is not possible to estimate the historical availability of imports for PJM. PJM administratively sets its capacity benefit of ties (non-firm imports) at 1.5% of nameplate generation procured in the capacity market, calculated here as 1.5% for 195,831 MW in the 2025/2026 Base Residual Auction. In its 2023 reserve margin analysis, PJM calculated 6,474 MW in total diversity benefit with its neighbors, much higher than the capacity benefit of ties shown in the table.

GridStrategies

SOURCE | EIA, "About the EIA-930 data" (accessed Feb. 2026); PJM, "2025/26 Base Residual Auction Report" (2024); Brooks, A. et al. (2025)

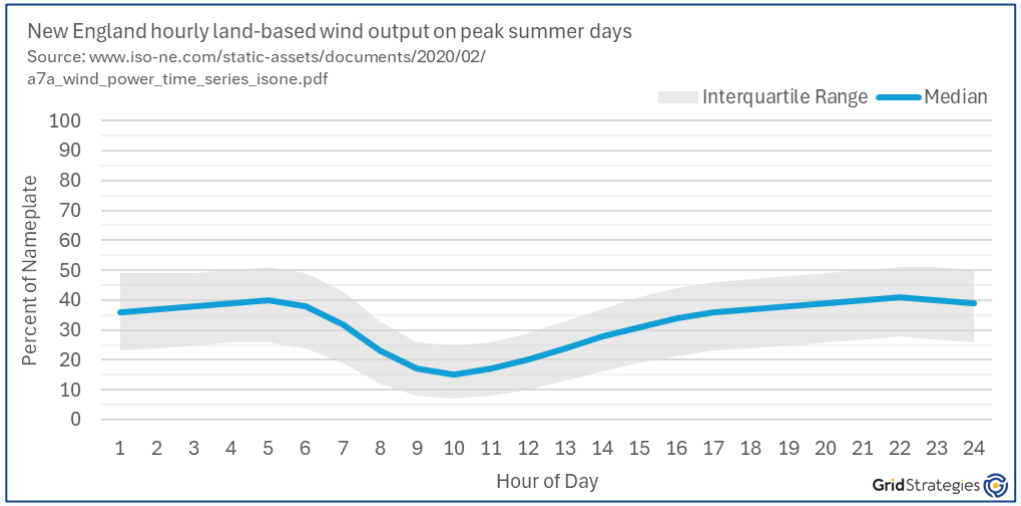
Analysis using LBNL data: New England wind and solar production

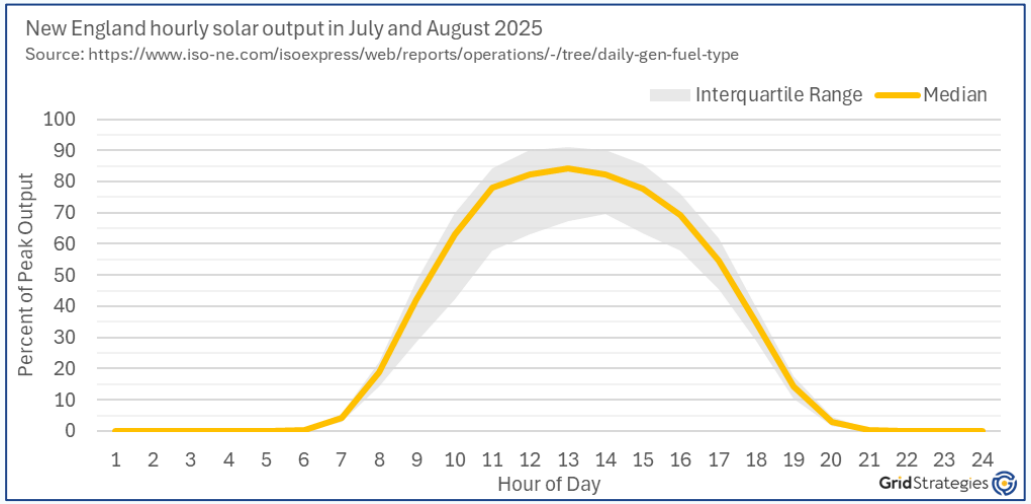
In order to use LBNL data for energy analysis for New England, we compare the amount of Tier 1 and Tier 2 LBNL data against NERC (slide 46). This required an understanding of the generation output in New England during summer months for different resource types.

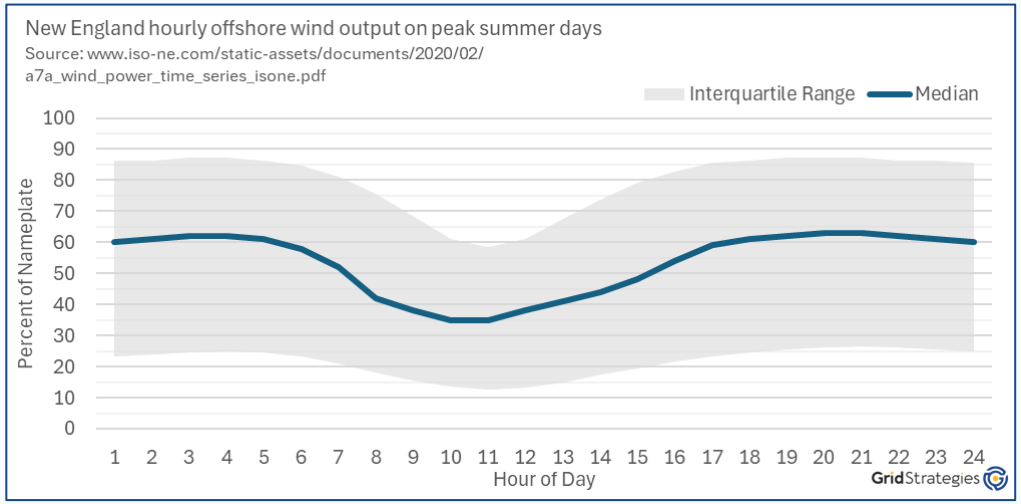
On the right are the hourly median and interquartile range for wind and offshore wind production in New England during peak demand days. This data was collected between 2012 and 2018 by ISONE to help them understand wind output during times of grid stress.

Also shown is the median and interquartile range for average hourly solar output in July and August of 2025, also from data collected by ISONE.

The hourly median data was used to estimate the output of both land-based and offshore wind in New England during peak summer 2029.







GridStrategies

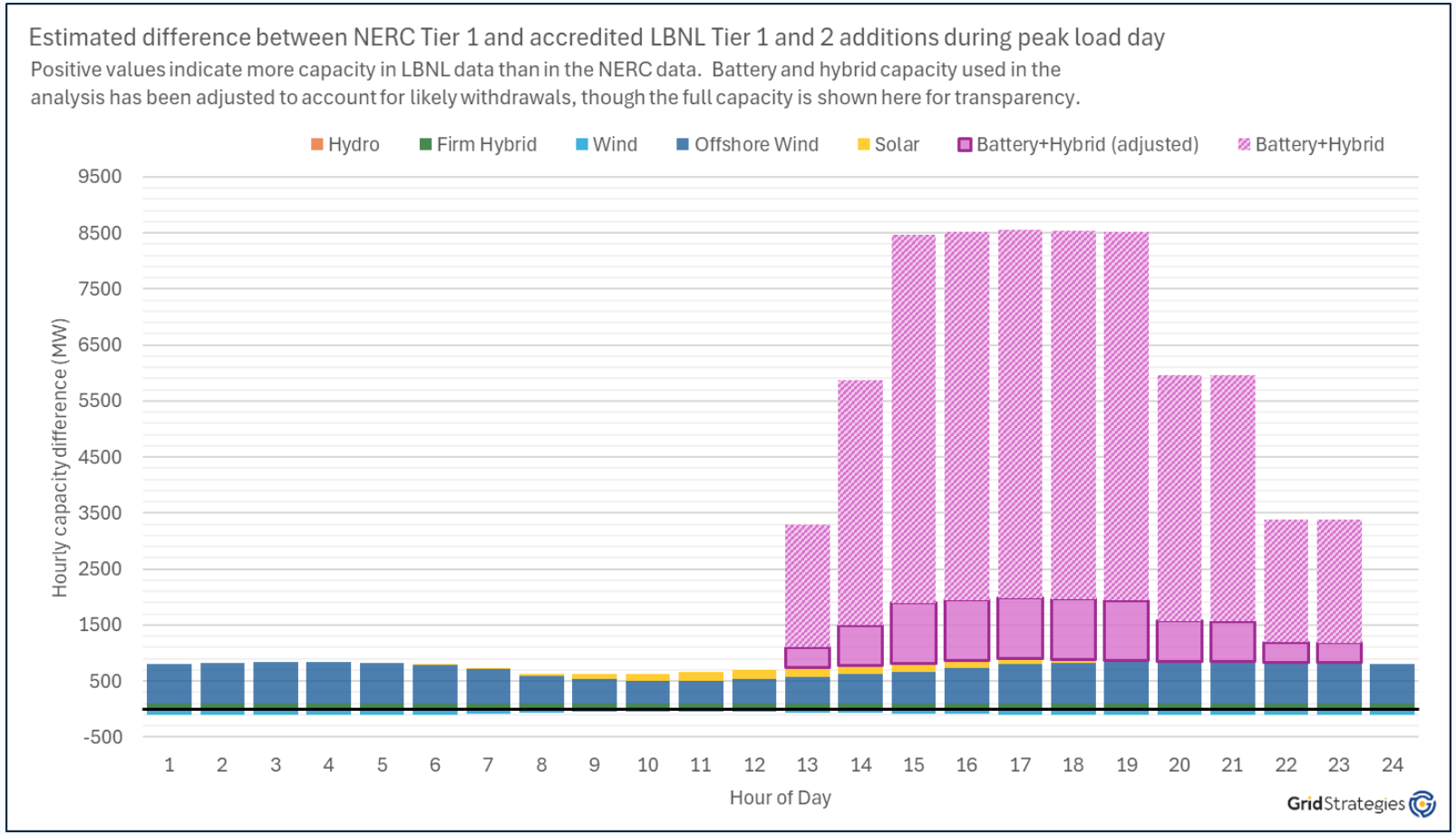
SOURCE | Judd, S. "Wind and Power Time Series Modeling of ISO-NE Wind Plants" (2020); ISONE "2025 Hourly Solar Generation" (2026)

Analysis using LBNL data: New England hourly production

Shown here is the potential change in hourly energy output for New England on peak load days given the different resource mixes between the LBNL and NERC data. Positive values indicate LBNL recorded more capacity for that resource type while negative values indicate NERC recorded more capacity.

As explained on slide 45, we adjusted the hourly production of each resource type to match expected peak day behavior, given regional resource accreditation methods. Battery and battery hybrid resources are expected to discharge at partial capacity for all hours of unserved energy, modulating their output so that no one resource discharges for longer than 6 hours. Given the large quantity of battery and hybrid resources in the LBNL data, these resources were additionally discounted by the historic withdraw rate of the region.

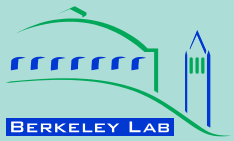
Given the data available, we cannot replicate the energy inadequacy analysis presented in the LTRA exactly. We provide this rough estimate to understand how different generation assumptions would impact unserved energy results.



SOURCE | NERC "2025 LTRA" (2026); NERC "2024 LTRA" (2025); NERC "ES&D" (2026); Rand, J. et al. (Aug. 2025)

EXHIBIT 109

LBNL- 1006395



ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Load Forecasting in Electric Utility Integrated Resource Planning

Juan Pablo Carvallo, Peter H. Larsen, Alan H. Sanstad, Charles A. Goldman.

Energy Analysis and Environmental Impacts Division

October 2016

This work was supported by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity (OE) Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

LBNL-1006395

Load Forecasting in Electric Utility Integrated Resource Planning

FINAL VERSION

Prepared for the
U.S. Department of Energy
National Electricity Delivery Division
Office of Electricity (OE) Delivery and Energy Reliability

Principal Authors

Juan Pablo Carvallo, Peter Larsen, Alan H. Sanstad, Charles A. Goldman

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

October 2016

The work described in this report was funded by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity (OE) Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Ernest Orlando Lawrence Berkeley National Laboratory is an equal opportunity employer.

Table of Contents

List of Tables iv
List of Figures v
Acknowledgements vi
Abstract vii
Executive Summary viii
1. Introduction 1
2. Background 3
3. Data sources and methods 5
3.1 Forecast information from plans 7
3.2 Information on actual energy use and peak demand 7
4. Description of forecasting methodologies 8
5. Quantitative analysis of forecast error 11
5.1 Comparison methods 11
5.2 Energy 12
5.3 Peak demand 15
6. Economic forecasts and revisions to load growth forecasts 19
6.1 Economic forecasts 19
6.2 Revisions of load growth rates in subsequent forecasts 21
7. Load forecast sensitivities in resource planning 26
7.1 Review of load forecast sensitivity methods 26
7.2 Quantitative analysis of load sensitivities 30
8. Comparison between older and recent plan load forecast methodologies 34
8.1 Changes to analysis framework 35
8.2 Changes to variables and analytical techniques 35
8.3 Changes to sources of key externally-produced assumptions 35
8.4 Evolution of forecasting methodologies and variables 36
9. Comparing load forecasts and resource planning & procurement 37
10. Summary and conclusion 39
11. References 42

12. Appendix A – Adjustments to data.....45
13. Appendix B – Demand forecast methodologies 46
14. Appendix C – Changes in load forecast methodologies from resource plans. 57
15. Appendix D – Description of load sensitivity analysis in older and recent IRPs. 70
16. Appendix E – Nameplate capacity expansion and load growth comparison.....76

List of Tables

Table 1 Load serving entities (LSEs) and integrated resource plans analyzed in this study. 6

Table 2 Modeling approaches for residential and commercial load forecasting. 11

Table 3 Sum of errors as a proportion of total load for forecast horizon of 2014. 13

Table 4 Average annual growth rate for actual and forecast load 15

Table 5 Peak demand average annual growth rates for forecasted and observed values. 16

Table 6 Avista – Forecasted and actual energy consumption growth rates to 2014 22

Table 7 COPSC – Forecasted and actual energy consumption growth rates to 2014. 22

Table 8 Idaho – Forecasted and actual energy consumption growth rates to 2014 23

Table 9 LADWP – Forecasted and actual energy consumption growth rates to 2014 23

Table 10 Nevada Power – Forecasted and actual energy consumption growth rates to 2014. 24

Table 11 Northwestern Energy 24

Table 12 PacifiCorp 25

Table 13 PGE 25

Table 14 PNM 25

Table 15 Puget Sound 25

Table 16 Seattle 25

Table 17 Sierra Pacific 25

Table 18 Summary of load sensitivity methods in older IRPs. 28

Table 19 Average annual growth rate for actual and forecast load, with sensitivities. 30

Table 20 Peak demand average annual growth rates for forecasted and observed values, including sensitivities. 31

Table 21 GDP deflator used to adjust monetary costs to real 2014 dollars. 45

List of Figures

Figure 1 Variables used for residential and commercial/industrial load forecasts, and model complexity. 10

Figure 2 Forecasted and observed energy consumption growth. 14

Figure 3 Forecasted and observed peak demand growth. 18

Figure 4 Intermediate energy consumption forecasts for Avista 2005-2011. 23

Figure 5 Intermediate energy consumption forecasts for Idaho 2006-2011. 24

Figure 6 Forecasted and observed energy consumption growth, with alternative load growth forecasts. 32

Figure 7 Forecasted and observed peak demand growth, with alternative load growth forecasts. 33

Figure 8 Load forecasting methodological changes since earlier IRP filing. 34

Figure 9 Planned and procured at-peak capacity with forecasted and observed peak demand. 38

Figure 10 Planned and procured nameplate capacity with forecasted and observed peak demand. 77

Acknowledgements

The work described in this report was funded by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity (OE) Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. The authors would like to thank Caitlin Callaghan and Matthew Rosenbaum (DOE OE) for their support of this project. The authors would also like to thank Galen Barbose, Joe Eto, Andrew Mills, and Lisa Schwartz (LBNL); Steve Johnson (Washington UTC); Phillip Popoff and Villamor Gramponia (Puget Sound Energy); James Gall and Grant Forsyth (Avista Corp.); Rakesh Batra and Caitlin Callaghan (DOE OE); and Aliza Wasserman (National Governors Association) for their thoughtful comments on earlier drafts. All remaining errors and omissions are the responsibility of the authors.

Abstract

Integrated resource planning (IRP) is a process used by many vertically-integrated U.S. electric utilities to determine least-cost/risk supply and demand-side resources that meet government policy objectives and future obligations to customers and, in many cases, shareholders. Forecasts of energy and peak demand are a critical component of the IRP process. There have been few, if any, quantitative studies of IRP long-run (planning horizons of two decades) load forecast performance and its relationship to resource planning and actual procurement decisions. In this paper, we evaluate load forecasting methods, assumptions, and outcomes for 12 Western U.S. utilities by examining and comparing plans filed in the early 2000s against recent plans, up to year 2014. We find a convergence in the methods and data sources used. We also find that forecasts in more recent IRPs generally took account of new information, but that there continued to be a systematic over-estimation of load growth rates during the period studied. We compare planned and procured resource expansion against customer load and year-to-year load growth rates, but do not find a direct relationship. Load sensitivities performed in resource plans do not appear to be related to later procurement strategies even in the presence of large forecast errors. These findings suggest that resource procurement decisions may be driven by other factors than customer load growth. Our results have important implications for the integrated resource planning process, namely that load forecast accuracy may not be as important for resource procurement as is generally believed, that load forecast sensitivities could be used to improve the procurement process, and that greater emphasis should be placed on strategies to manage uncertainties in load forecasts.

Keywords: resource planning, forecast error, load, retrospective analysis, resource expansion, electric utility.

Executive Summary

Integrated resource planning (IRP) is a process used by many vertically-integrated U.S. electric utilities to determine least-cost and risk-managed portfolios of supply and demand-side resources that meet future electricity needs of customers, comply with regulatory requirements and government policy objectives and, in many cases, fulfill obligations to shareholders. Integrated Resource Planning evolved in the late 1980s and 1990s from least-cost planning (LCP), which was developed to ensure that demand-side measures to reduce electricity consumption—especially end-use energy efficiency—were considered by utilities in addition to supply-side (generation) resources. Forecasts of energy and peak demand are a critical component of the IRP process. There have been few, if any, quantitative studies of IRP load forecast performance and its relationship to resource planning and actual procurement decisions.

In this study, we conduct a retrospective analysis of energy and peak demand forecasts for a set of integrated resource plans published by electric utilities operating in the Western United States. We analyze energy and peak demand forecasts from utility IRP plans filed in the early- and mid-2000s and compare these forecasts to subsequent actual observed loads. We also examine load forecasting techniques and sensitivity analyses; performance over time; the relationships among load forecasting, resource planning, and procurement; and strategies that utilities used to manage uncertainties in future load forecasts.

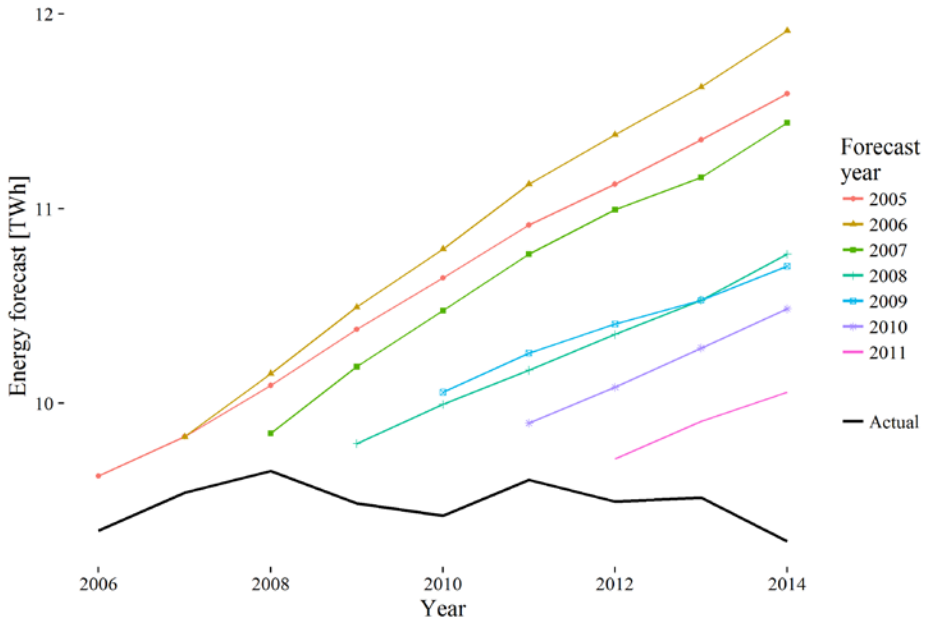


Figure ES-1 Load forecasts from seven subsequent IRPs and actual load for a Western U.S. utility.

A comparison of load forecasts to actual energy use and peak demand reveals that energy consumption growth was overestimated by all but one utility over planning periods beginning in the mid-2000s and ending in 2014. Moreover, peak demand growth was also overestimated in eight of the eleven cases we examined (those utilities that reported their peak forecasts). Utilities that projected the highest growth rates in energy and peak demand also experienced the lowest actual growth, especially for observed energy consumption.

Furthermore, examination of forecasts from more recent IRPs indicates a persistent overestimation of demand growth over planning periods up to year 2014, even in the presence of much slower-than-anticipated actual growth (see Figure ES-1 for an example from one utility). A number of the utilities highlighted the effects of the national recession that began in 2008-2009 to explain this phenomenon. Over time, the utilities did adjust their forecasts of projected load growth downward in response to lower-than-expected demand, but continued to overestimate future loads. Most of the utilities indicated that they expected national and regional economies would follow a historical pattern of relatively quick recovery from the recession, which influenced their load forecasts in more recent plans. Accordingly, the slower-than-expected economic recovery contributed to over-estimates of future load in more recent IRPs.

We find some correlation between forecasting methods—and their relative complexity—and forecast accuracy. In addition, utilities that had the most accurate peak demand forecasts were also among the most conservative in terms of their expected peak demand growth. Utilities with relatively more complex models had less forecast error than those that employed simpler models. There are structural reasons that may also explain the relative accuracy of load forecasts. For example, we find that utilities with a larger share of industrial load in their mix generally had larger forecast error. We believe that this may be caused by the highly elastic and “lumpy” nature of industrial customer load as well as the difficulty in predicting entry and exit of industrial customers from a utility service territory. These results suggest that, among the utilities we studied, there may be small marginal benefits to the planning process of greater model complexity.

Load forecast sensitivity analysis is an important component of risk assessment and management within IRP process. In the context of our study, sensitivity analyses are especially important because strategies derived from load forecast sensitivity analysis may allow the resource plans to adjust as new information comes in. Over time, we find that utilities have improved the breadth and sophistication of their load forecast sensitivity analyses. However, we find that both older and more recent IRPs generally lack an adaptive component that details how utilities would respond in practice were subsequent actual values of critical input variables—like load — to correspond to those studied in these sensitivity analyses rather than to those assumed in "base cases." We also find that load variation from the base case produces differences in projected revenue requirements for utilities that are much larger than the differences in revenue requirements from the resource portfolios that are designed and compared to select the “preferred” one.

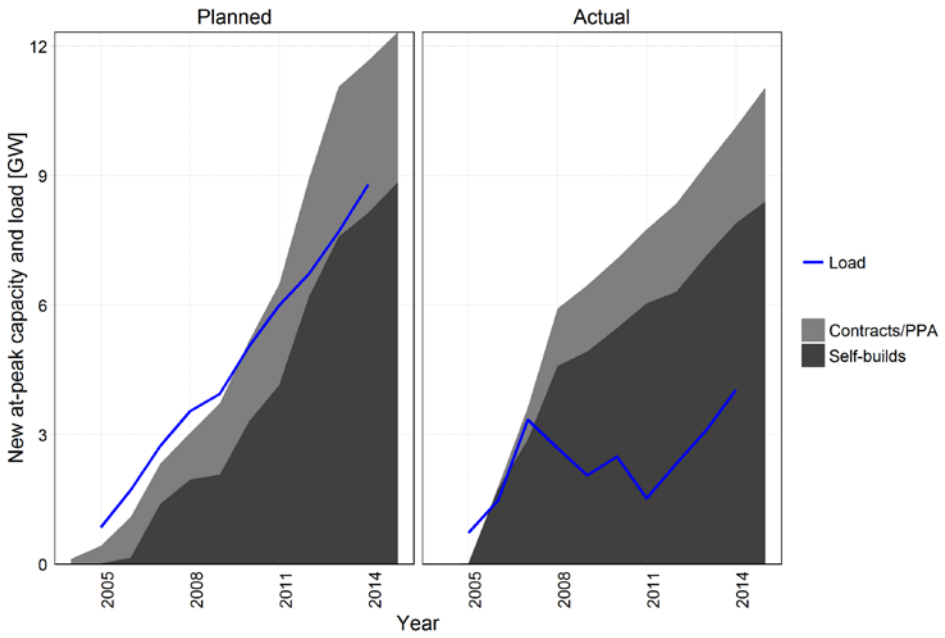


Figure ES-2 Planned and actual (procured) at-peak capacity with forecasted and observed peak demand.

For this sample of utilities, we find that aggregate planned and actual capacity expansion levels were generally consistent over the time period of our study. However, in aggregate, actual resource procurement decisions were not closely aligned with observed changes in load (see Figure ES-2). Actual incremental capacity additions were partially attributable to retirements of existing plants, which accounted for about 2.5 GW among our sample of utilities.

We find that load forecast methodologies have not changed significantly in the past 15 years, although there is evidence in more recent plans of the inclusion of potential structural change drivers such as distributed energy resources and electric vehicles. We did find that utilities which fundamentally changed their forecasting techniques had relatively larger forecast errors in earlier periods. This suggests an active effort to by the utilities to react to forecast error, although we do not have evidence that these changes led to reduced forecast error in subsequent periods. In general, we believe that our findings of load forecast performance and their relationship to procurement are applicable to current resource planning and procurement processes.

Our findings suggest that (1) load forecast accuracy may not be as important for resource procurement as previously believed, (2) load forecast sensitivities could be used to improve the procurement process, and (3) comprehensively addressing load uncertainty should be prioritized over developing more complex forecasting techniques. To the best of our knowledge, this is the first comparative and retrospective study of long-range energy and peak demand forecasts for electric utilities. We identify several key topics for further research to better understand the results and inform industry stakeholders about the role that load forecasts play in electricity sector infrastructure investments.

1. Introduction

From the origins of the U. S. electricity industry in the 19th century with Thomas Edison's first power-generation plant in New York City, electric utility planning and operations have become highly complex, multi-faceted processes. Electric utility integrated resource planning (IRP) is the key mechanism through which many vertically integrated U. S. utilities or load-serving entities (LSEs) [1] operating in states with a regulated electricity sector determine how to provide electricity services to customers while complying with applicable energy and environmental regulations and policies, and respecting the economic objectives of both the utility and customers. IRP entails the use of a range of quantitative analytical methods, including computational modeling and statistical analysis. The IRP applications of these methods include forecasting variables including load - electricity consumption and peak demand, analyzing possible "portfolios" - combinations of types and amounts of generation, assessing energy efficiency and other means of influencing demand and ensuring that supply and demand are balanced over a specified planning horizon. By design, the IRP process involves multiple stakeholders beyond utilities themselves, including regulators, ratepayer advocacy groups, other entities within the power industry, and non-profit organizations.

Electric utility integrated resource planning has its origins in "least-cost planning," a methodology developed in the 1970s to incorporate "demand-side resources" – measures to promote energy efficiency and conservation – along with the supply-side resources, i.e., generated electric power, that had traditionally been the sole focus of utility planning. Over the past several decades, the technical tools and methods used in IRP have become more complex and the requirements placed upon IRP – with regard to goals and objectives as well as process guidelines – have increased. Concurrently, there has been increasing interest among researchers, regulators, and other stakeholders in understanding the details of how IRP is conducted and how its outcomes relate to its goals, and in ways to enhance and improve IRP both technically and from a process perspective.

Among their other provisions, state regulatory requirements for IRP generally stipulate openness with respect to information, involvement of non-utility and other stakeholders besides regulators, and similar process elements. They do not in general, however, require actual evaluation or validation of models or methods.[2] While not an evaluation or validation analysis as such, the work described in this paper builds upon previous reviews and assessments of IRP, including

[1] "Load-serving entity" is a more precise term than "utility" to refer to firms that sell electric power to end-use customers. However, in this paper these terms will be used interchangeably.

[2] Although for reasons discussed later in the paper we do not include IRPs by large California investor-owned utilities in our analysis, California is an exception in that its state public utilities code explicitly stipulates that models used in electricity planning and operations be validated. It is also interesting to note that the U. S. Energy Policy Act of 1992, which requires utilities to conduct integrated resource planning, also stipulates that approval of utility-submitted IRPs by regulators of the Western Area Power Administration is contingent upon the fulfillment of several criteria including that the utility "[provide] methods of validating predicted performance in order to determine whether objectives in the plan are being met."

load forecasting and dating back to the 1980s, by outside researchers, with recent examples being Aspen and E3 (2008) and Wilkerson et al. (2014). It is aimed at contributing to the understanding of IRP and focuses on the methods, results, and planning applications of utility load forecasting.

Estimates of load over time horizons up to two decades are a cornerstone of the integrated planning process: notwithstanding the multiple purposes and aspects of IRP, the LSEs' core objective and obligation is to ensure reliable and affordable electricity supplies for their customers. Load forecasting is thus of *prima facie* interest in analyzing and assessing IRP.

In addition, as noted above the treatment of demand-side resources has been a central motivation for IRP dating back to the 1970s, and utilities' incorporation of energy efficiency and related measures is fundamentally based upon their analyses and forecasts of load and the factors affecting it. This element of IRP has only increased in importance in recent years, as increasing energy efficiency and demand response has become a goal of a growing number of U. S. states and utilities. From both analytical and regulatory-policy perspectives, understanding how efficiency is analyzed within and implemented through IRP requires first understanding LSEs' basic load forecasting techniques, methods, and results.[3]

Despite these considerations, there has been little analysis of load forecast *performance* – i.e., accuracy - in the context of IRP, nor of how it is related to utilities' procurement decisions. These decisions include building or acquiring of power generation plants, purchasing power from other sources, implementing demand-side management programs, and other means of securing electricity supplies and services for their customers. This paper aims to help fill this gap, and reports the results of an analysis of load forecasting conducted in the mid-2000s by twelve utilities in the western United States. We complement our analysis by examining, in addition, recent plans for each of these utilities. It is the first of a two-part study of the relationship between planning and procurement in utility IRP. It explores the role of load forecasting in planning and how its accuracy relates to potential differences between planning and procurement. The second paper will analyze in greater depth and detail the regulatory process that connects the planning process with procurement decisions.

The paper is organized as follows. We begin with an overview of previous research on various elements and aspects of IRP in Section 2 to situate our work. We then describe the sources of data used for our analysis, followed by a discussion of the LSEs' forecasting methods and inputs in Section 3. Next, the metrics used to compare forecasts to actual energy and peak demand are defined in Section 4, followed by our quantitative findings on forecast performance in Section 5. We then turn to a discussion of the economic-demographic projections used in the forecasts and their relationship to forecast accuracy, and present a quantitative review of the LSEs' projected growth rates and retrospectively-revealed forecast errors in successive IRPs in Section 6. Next, in Section 7 an analysis of load sensitivity methodologies and performance is conducted along

[3] Experience in California has demonstrated that understanding the role of efficiency and efficiency policies and programs in load and demand forecasting can be very challenging (REF DAWG).

with a discussion of changes to LSEs' load forecasting methods and inputs over time in Section 8. We present a summary of results comparing the load forecasts to planned and actual procurement in Section 9. The study concludes with a summary and suggestions for further research.

2. Background

Descriptive as well as critical reviews of least-cost planning and IRP began to appear in the 1980s, as these processes were adopted across the U. S. In keeping with the origins of this type of planning, some of this literature included discussions of IRP's treatment of energy efficiency and conservation, and the potential for "demand-side management (DSM)" programs to reduce load growth. More generally, it included analyses of factors within (i.e., endogenous)—and beyond (i.e., exogenous)— the control of LSEs that impact the performance of forecasts including (1) forecasting methods employed by planning departments; (2) company and technological characteristics; and (3) the broader economic and regulatory environment (Goldman et al., 1993).

Hirst (1989) reported findings from a case study of, and drew lessons from, a specific planning exercise by a utility in the Pacific Northwest. Hirst (1990) and Hirst et al. (1991b) reviewed more than 30 resource plans from electric utilities, focusing on "technical competence" - including load forecasting — and made recommendations for improvements; in the case of load forecasting, however, these recommendations were not based on a quantitative analysis but rather emphasized methodological issues, especially the treatment of DSM. Hirst (1994) also critically reviewed key elements of IRP as practiced by utilities at the time, including load forecasting, and identified best practice. Schweitzer et al. (1991) reviewed plans from more than 20 load-serving entities with an emphasis on demand-side management activities. Hirst et al. (1991a) surveyed the regulatory, institutional and technical status of IRP at that time – including the treatment of DSM in load forecasting – and made recommendations for improvement in each category. Sioshansi (1992) explored the effect of incorporating technologies—including demand-side management and energy efficiency—on electric utility resource processes, plans, and outcomes. Mitchell (1992) surveyed the status of IRP with respects to its adoption and implementation across U. S. states. Aspen and E3 (2008) reviewed IRP planning processes and methods across U. S. states, and compared critical assumptions, timeframes, models, and procurement processes used by nearly 20 LSEs across the Western U.S., including inputs to and methods for load forecasting. Wilson and Biewald (2013) identified IRP "best practices," including examples of load forecasting by specific utilities and recommendations for load forecasting improvements, while a study conducted for U. S. state energy policy-makers examined how utilities' load forecasting is taking account of the emergence of electric vehicles (NASEO 2013). Wilkerson et al. (2014) reviewed nearly 40 long-term electric utility plans representing ~90% of generation within the Western United States and Canadian provinces, and identified assumptions about future growth of electricity demand and supply, the types of risk

utilities consider in their long-term resource planning, and the consistency in which utilities report resource planning-related data.

In addition to these studies dealing at least in part with technical matters, a number of studies have addressed institutional and contextual aspects of IRP. For example, English et al. (1995) analyzed the role and impacts of energy efficiency advocacy groups in planning processes, while Hirst (1988) discussed state public utility commissions' roles in and responsibilities for IRP, and Hadley and Hirst (1995) discussed utility IRP from the electric utility shareholder perspective. More recently, Wilson and Peterson (2011) surveyed the rules and regulations governing IRP across U. S. states.

Complementing this work on IRP *per se* has been research on computational modeling in electricity planning. Eto (1990) and Foley et al. (2010) discussed models and software used in electricity planning. Kahn (1995) analyzed the advent of "production cost (optimization) modeling" by utilities in regulatory processes, including those involving IRP. Rosekrans et al. (1999) reviewed and compared several electricity planning models, many of which are used in IRP.

Despite reviews and discussions of load forecasting among other technical aspects of IRP, the work summarized above has not quantitatively studied load forecast nor analyzed its accuracy. By contrast, several papers from the 1980s did so. Willis and Northcote-Green (1984) compared methods and accuracy of 14 distribution system load forecasts. Nelson and Peck (1985) analyzed "summary" load forecasts from the 1970s prepared by the National Electricity Reliability Corporation (NERC), which combine individual utility service territory- and regional-level forecasts into a national-level forecast. They found systematic over-projection of demand. Mitchell et al. (1986) retrospectively evaluated the accuracy of long-term load – both energy and peak – forecasts by utilities, government agencies, and academic researchers. However, none of these studies analyze the impacts of forecast error and the feedback between forecast performance, planning and procurement.

While short-term electric load forecasting has been and continues to be the focus of considerable research, these older studies of long-term forecast performance have not been followed up by more recent work nor have they been expanded to understand the implications of forecast performance in the planning and procurement process. In the following sections we present the results of our analysis, which addresses this topic.

3. Data sources and methods

Our quantitative analysis of forecast performance relies largely on two types of data: forecasts and actual[4] values. In this section, we describe the methodology to obtain this information, the original sources of the data, and how this information is used throughout the analysis. The same sources are used for the qualitative descriptions of load forecast and load growth sensitivity methodologies.

We collect forecasts from integrated resource plans that were made roughly a decade ago – from 2003 to 2007 – by twelve load-serving entities (LSEs) across the Western Electricity Coordinating Council (WECC). The analysis focuses on WECC because this territory includes the largest U. S. LSEs that were required to file resource plans during this period (Wilkerson et al., 2014)[5]. However, we exclude three large California investor-owned utilities (IOUs), because the California planning framework – the so-called "Long Term Procurement Planning" process – is qualitatively different from the other resource planning mandates in WECC (Aspen and E3, 2008). Outside of the California IOUs, the LSEs selected for this study are the twelve largest in WECC representing 34% and 32% of customers and retail sales in 2014, respectively.

The years for the IRPs are selected in order to enable comparison with realized observations – i.e., observed values of energy and peak demand — through 2014, the most recent year for which these values are currently available (see Table 1). Depending on the LSE, between seven and eleven years of observed energy and peak demand can be compared to the original forecast.

The choice of years also satisfies several other criteria. First, we need plans that were created sufficiently long ago that their forecasts can be compared to observed values over periods lengthy enough to allow substantive analysis[6]. Second, plans that are older than those selected tended to have several shortcomings: the information included in them was scarce, both in terms of data and descriptions; the techniques for forecasting may have changed significantly; and the electricity deregulation movement in the late 1990s may have had an important effect on their assumptions. Because the earliest plan (2003) followed the California electricity crisis of 2000-2001, we presume that the effects of deregulation would have already been absorbed in the planning processes. We believe that using plans from 2003 and later enables reasonable conclusions about trends and the implications of policies. Finally, we also reviewed one recent plan (produced between 2011 and 2015) for each LSE to understand if and how the methodologies and techniques used to produce forecasts had changed in time.

[4] We refer to these also as "realized" or "observed" through the paper.
[5] ERCOT and the Eastern Interconnection utilities filed no or very few resource plans in the early 2000s, largely due to the deregulation process.
[6] In the case of PNM and PGE we selected the oldest plans we were able to find that included the required data. PNM filed its first resource plan in 2005 but it did not include most of the quantitative data required for the analysis.

Table 1 **Load serving entities (LSEs) and integrated resource plans analyzed in this study.**

LSE short name	LSE name	First Plan Year	Recent Plan Year	Reference
Avista	Avista Corporation	2005	2013	(Avista, 2013, 2005)
COPSC*	Public Service Company of Colorado (Xcel Energy)	2003	2011	(COPSC, 2011, 2004)
Idaho	Idaho Power Company	2006	2013	(Idaho, 2013, 2006)
LADWP	Los Angeles Department of Water and Power	2006	2012	(LADWP, 2012, 2006)
NVPower	Nevada Power Company	2006	2012	(NVPower, 2012, 2006)
NW	NorthWestern Corp. dba NorthWestern Energy	2004	2013	(NW, 2013, 2004)
PacifiCorp	PacifiCorp	2004	2015	(PacifiCorp, 2015, 2005)
PGE	Portland General Electric Company	2007	2013	(PGE, 2014, 2007)
PNM	Public Service Company of New Mexico	2007	2011	(PNM, 2011, 2007)
PugetSound*	Puget Sound Energy, Inc.	2005	2013	(PugetSound, 2013, 2005)
Seattle*	Seattle City Light	2006	2012	(Seattle, 2012, 2006)
SierraPacific*	Sierra Pacific Power Company	2004	2013	(SierraPacific, 2013, 2004)

* These LSEs are also known as PSCo (COPSC), PSE (PugetSound), SCL (Seattle), and SPP (SierraPacific). We use our own short names through this paper.

The analysis period includes the 2008 economic recession, which *prima facie* could be expected to have a substantial effect on the accuracy of load forecasts made prior to its onset. For several reasons, however, we see this as increasing the interest and usefulness of our analysis. First, it is a truism that all forecasts - including those of electricity use - are subject to error due to unforeseen circumstances. The documentation indicates that the LSEs view economic and demographic variables as the primary drivers of demand, and the inevitability but always uncertain timing of events such as recessions means that such events are essentially guaranteed to affect long-term load forecasts in not-fully-predictable ways, regardless of the forecast interval. Thus, an analysis period including the downturn that began in 2008 - which was unusually severe - can if anything allow greater insight into the nature of load forecast accuracy and how forecast errors are addressed in the IRP process than might be available from studying a period without such an event. Put differently, the 2008 recession provides an interesting "stress test" of LSE load forecasting procedures in the context of IRP. Second, because the recession affected all regions of the U. S. to some extent, including the service territories of the LSEs in our sample, it does not undermine our comparative analysis and indeed, to the extent that the

effects of the recession varied across these territories, adds useful variation to our sample. Finally, the procurement activities following the IRP load forecasts necessarily also reflected the recessions' effects, and thus the latter do not interfere with our goal of studying the relationships between load forecasting and procurement.

3.1 Forecast information from plans

Our analysis considers specific information from resource plans including utility forecasting techniques, company characteristics, and the regulatory environment. Three basic types of forecast data are collected from each IRP:

1. Peak load
2. Energy demand
3. Demand side resources (energy efficiency and demand response)

We record the base- or reference- case load forecast in each resource plan (all the LSEs produced these cases for energy, and all but one for peak). We also record high and low load forecasts when available. Utilities that file resource plans do not always have the same definition of their "position," i.e., the difference between existing resources and forecasted demand. For example, LSEs deal differently with energy efficiency and demand response measures. Some subtract projected savings from these resources into their load forecasts, and some report them separately. For the forecasts that had not already done so, we subtract these savings from the raw energy and peak demand forecasts in order to calculate net load[7]. The use of net forecasts is appropriate for comparison with actual energy and peak demand, since the latter have embedded within them the effects of demand-side programs and other acquired energy efficiency over the periods considered in the analysis.

3.2 Information on actual energy use and peak demand

Data on actual energy consumption and peak demand were obtained primarily from the Velocity Suite system supplied by ABB-Ventyx—an online database system that compiles publicly-available data and also contains proprietary values for variables that are not always publicly-available, including retail fuel prices and marginal costs (ABB-Ventyx, 2016).

The Velocity Suite system contains load data (retail sales), which are typically reported through the Energy Information Administration (EIA) Form 861. As defined by the EIA, "The Form EIA-861 and Form EIA-861S (Short Form) data files include information such as peak load, generation, electric purchases, sales, revenues, customer counts and demand-side management programs, green pricing and net metering programs, and distributed generation capacity." (EIA,

[7] By doing this, we implicitly include in our assessment the performance of energy efficiency and demand response forecasts. We recognize that the actual demand side resources may differ from these forecasts, but we lack the data to test this.

2016) In order to conduct forecast-to-actual comparisons, it is necessary to identify the types of sales that utilities themselves considered as part of the "position" for the resource planning process. We determine that all IRPs account for retail sales to ultimate consumers when creating their forecasts, and that all except LADWP and COPSC include transmission and distribution losses to reflect demand at the generation level. Therefore, we incorporate losses into the retail sales information reported via form EIA-861.

In addition, we inspect the IRP narratives and quantitative information to determine which LSEs account explicitly for selected wholesale sales for which they had firm contracts at the time of the forecasts. For example, short-term transactions that are used as hedging or as a market opportunity would typically not be included in the resource plan. However, sales to smaller municipalities and electric cooperatives under certain contracting arrangements would be included. We find that all LSEs, with the exception of NW, counted "requirements service[8]" wholesale sales in their resource plans. We use data from EIA Form 412 and FERC Form 1 to identify and include appropriate wholesale sales as part of actual outcomes for each LSE. Finally, we use historical information presented in the most recent plans of the several LSEs that reported it to check our estimates for actual values.

4. Description of forecasting methodologies

We characterize the methods employed by LSEs to forecast energy, peak demand, and hourly profiles using the following categories:

1. General forecasting framework—e.g., the mix of customer classes evaluated, makeup of forecast scenarios.

2. Key variables and analytical methods—e.g., time-series regression, statistically-adjusted end-use models, cooling degree-days, number of customers.

3. Sources of forecast assumptions—e.g., IHS Global Insight, Inc., EPRI, Moody's Analytics, Inc.

We provide an overview of the LSEs' load forecasting; further details are given in Appendix B. In addition to the base case or "expected" forecasts, most of the LSEs also produce low and high load forecasts using differing assumptions. We summarize and analyze these alternative forecasts in section 7 and Appendix D.

LSEs typically split their residential and commercial forecasts into numbers of customers and use-per-customer, using different methods to forecast both separately. Industrial consumption forecasts are usually based on direct feedback from the largest customers, complemented with

[8] According to EIA-861, "Requirements service is service which the supplier plans to provide on an ongoing basis. The reliability of requirement service must be the same as, or second only to, the supplier's service to its own consumers."

regional or sectoral market research reports. Only a few of the LSEs evaluated in this paper reported load forecast results by customer class.

We find that roughly three quarters of the LSEs in our sample relied on externally-developed demographic and economic forecasts. These external forecasts came from a mix of public and private sources, including universities, state/federal agencies, and consulting firms. We also find that most of these sources are proprietary, which prevents scrutiny from stakeholders and further analysis from regulators.

Another key component of a number of the load forecasting frameworks is the potential for customers to respond to changes in electricity prices (i.e., price elasticities) through a combination of electric consumption reduction and fuel switching. For example, as the price of electricity increases or the price of natural gas decreases, it is expected that electric load will decrease and natural gas consumption increase as a rational response to these price signals. About half of the LSEs in our sample reported specific information about price elasticities—with all falling within the -0.10 to -0.20 range (NVPower, PugetSound, Avista, and PacifiCorp)[9]. Avista is the only LSE that reports cross-price elasticities with natural gas, although Idaho also points that "changes in relative fuel prices can have significant impacts on the future demand for electricity" (Idaho, 2006, p. 4 Appendix B). In contrast, NW and SierraPacific report that they find no empirical evidence for statistically significant price elasticities for electricity or for natural gas.

We evaluate these and other variables in order to understand the similarities and differences among the LSEs' forecasting procedures (see Figure 1). We find economic-demographic projections, historical sales data, and weather variables to be the most commonly-used variables to produce load forecasts. For each LSE, we also qualitatively assess the complexity of the load forecast by comparing the number of variables used to forecast residential and commercial/industrial demand and the analytical methods employed (see Table 2). For example, utilities including PNM, NW and SierraPacific use simpler models compared to the models employed by COPSC, LADWP, and PugetSound. This complexity is a function of the number of variables, the types of variables, and the modeling technique and its implementation.

Four types of modeling approaches, of varying degrees of complexity, were used by the various LSEs to create energy, peak demand, and hourly load forecasts: Time-series regression, cross-sectional regression, engineering or "bottom-up", and statistically adjusted end-use (SAE). Time series and cross-sectional regressions consistently use historical sales and weather variables as determinants of electricity demand. SAE models have a hybrid structure combining engineering end-use technology models with econometric equations. This type of data intensive model represents demand in terms of a saturation component (for appliance ownership), an engineering component (for appliance energy intensity), and a behavioral component (Hirst et al., 1977; Hirst

[9] Unfortunately, no LSEs indicate whether they report short or long term price elasticity values.

and Carney, 1978; Sanstad et al., 2014). SAE models were employed by three of the twelve LSEs in our sample, while the two "pure" regression models are used by the majority of the LSEs. We identify what method is used for both residential and commercial customer classes. In a few cases, however, methods are not customer class-specific. For example, PacifiCorp uses a moving average method for short-term forecasting and an SAE for long term projections. Similarly, SierraPacific uses an ARIMA (auto-regression, integrative, moving average) method for the number of customers and a regression method for the use per customer.

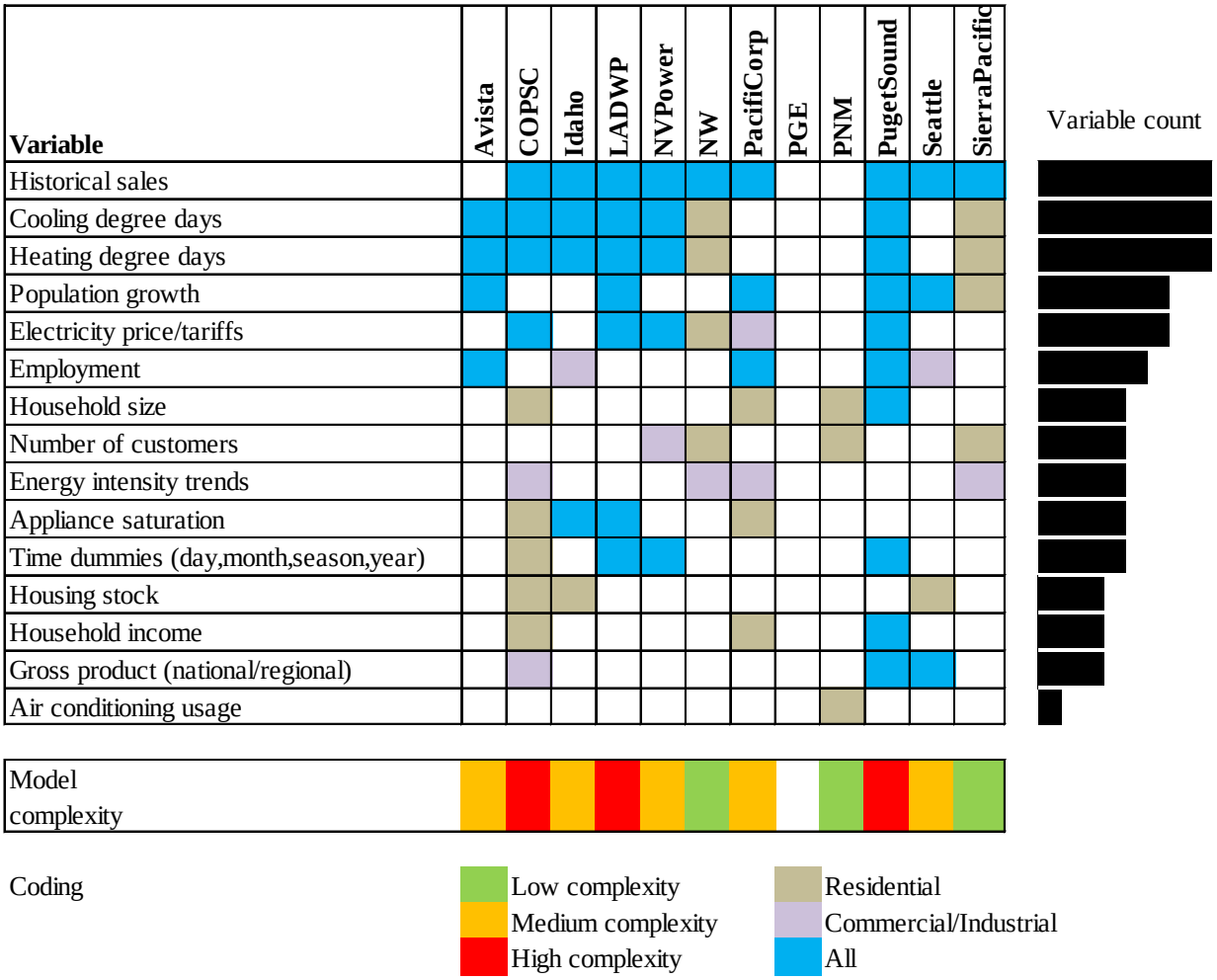


Figure 1 **Variables used for residential and commercial/industrial load forecasts, and model complexity[10].**

Finally, the breadth and depth of technical documentation on load forecasting varied quite widely among the LSEs in the older IRPs. In some cases, detailed information – including input types and values, mathematical formulae, and parameter estimates - were provided; in others, there was only narrative description. In no case, however, was there sufficient information to actually

[10] There is no information available for PGE in their 2007 plan. Blank spaces means that the variable is not documented or formally employed in the forecast.

replicate the individual LSE forecasts or to test their sensitivity to the error in the input parameters. This general inability to replicate individual LSE forecasts prevents stakeholders from critically examining the assumptions, techniques, and results of the load forecast.

Table 2 **Modeling approaches for residential and commercial load forecasting[11].**

	Time series regression (AR*, MA**)	Cross-section regression	Engineering model	SAE
Avista		RC		
COPSC				RC
Idaho				RC
LADWP		RC		
NVPower	RC	RC		
NW	C	R		
PacifiCorp				
PGE				
PNM			RC	
PugetSound		RC		
Seattle		RC		
SierraPacific				

*AR: Auto-regressive; **MA: Moving Average
R: Residential; C: Commercial

5. Quantitative analysis of forecast error

We are interested in assessing the impacts of forecast errors in the electric planning and procurement process. In this section we numerically compare the energy and peak demand forecasts reported by LSEs in their IRPs to actual outcomes over the corresponding period.

5.1 Comparison methods

We employ two different metrics to compare forecasts to actual results - i.e., to estimate forecast errors (Hyndman, 2006):

- *Sum of errors*: Annual forecast errors for each LSE were calculated as the differences between that LSE's forecasted value and the actual value for each year of the forecast. We divide the sum of these errors by the corresponding sum of total load that was actually realized by the LSE during the forecast period. This serves to normalize the metric in order to compare forecast performance across LSEs of varying sizes. This technique averages out positive and negative deviations, which is useful for identifying systematic error that is expected given the variability of loads.

[11] There is no information available for PGE in their 2007 plan.

- *Annual average growth rate (AAGR):* We compare the first and last year forecast and actual values to estimate an average annual growth rate for each. The AAGR represents the rate at which the first year forecast or actual value would need to grow to match the final year assuming a compound growth rate. This relationship is captured in equation (1) and (2) below:

$$Y_{t+n} = Y_t \times (1 + AAGR)^n \quad (1)$$

where Y_t is a forecast variable of interest (in our case energy and peak demand). Rearranging terms we have:

$$AAGR = \left(\frac{Y_{t+n}}{Y_t}\right)^{\frac{1}{n}} - 1 \quad (2)$$

The sum of errors is a relative metric, so a larger % difference implies larger forecast error over the time period of analysis. The AAGR captures, on average, the implied growth rate for a given variable. The difference between a forecast and an observed growth rate is, in this case, a measure of forecast error. We characterize the error in load forecasting (i) to understand how it may be correlated with specific methods, variables, or sources and (ii) to compare how these load forecast results relate to resource acquisition (see section 9).

5.2 Energy

Figure 2 shows normalized energy consumption forecasts and observed and equivalent for each LSE. This normalization yields growth rates for both forecasted and observed values. The analysis time frame corresponds to the range of years between the first year in the forecast and 2014 (the most recent year for which we have observed values). In some cases, sales seem relatively inelastic to the 2008 economic crisis and actual energy sales are close to the base forecast. However, sales for most LSEs stalled during and after the recession.

We compare the sum of errors in each LSE's analysis period with the sum of actual energy consumed in that period (Table 3). The immediate conclusion from this table is that proportional forecast error varies importantly across the LSEs in our sample, ranging from close to zero to almost 20%. The usual affirmation that "all forecasts are wrong" may be valid, but our empirical analysis suggests that, whether by chance or for other reasons such as methodological differences, forecast error in the analysis period is significantly smaller for some utilities than others[12].

[12] With this metric, forecasts from earlier plans have greater chance of having larger proportional error. However, we do not find a correlation between age of plans and error in our analysis, probably because the plans are at most 3 years apart.

Table 3 **Sum of errors as a proportion of total load for forecast horizon of 2014.**

LSE	Sum of errors (1) [TWh]	Sum of actual load (2) [TWh]	Proportional Error (1)/(2)
PGE	29.12	151.31	19%
Avista	14.73	85.36	17%
NVPower	26	199.01	13%
SierraPacific	10.57	89.37	12%
Idaho	13.47	138.43	10%
PNM	5.64	85.17	7%
COPSC	21.41	365.05	6%
LADWP	13.04	236.45	6%
PacifiCorp	33.43	580.63	6%
Seattle	5.15	100.48	5%
PugetSound	2.09	206.15	1%
NW	-1.29	68.5	-2%

In the analysis from Figure 2, the growth rate reflects the ratio between a given year's forecasted value and the first year forecast (and similarly for observed values). Growth rates are relevant because they convey expectations for potential resource needs that are independent of consumption levels and of existing resources. We see more clearly that some LSEs were more resilient or insensitive than others to the recession and that several have not shown signs of recovery in energy sales growth rates by 2014. In some cases (e.g. LADWP, COPSC, and PacifiCorp) we see that energy forecasts before the economic crisis seemed underestimated compared to actual load growth in that period. This may have been due to higher than anticipated economic activity during the "bubble" that preceded the economic downturn.

We calculate the Average Annual Growth Rate (AAGR) to facilitate comparison of growth estimates (Table 4). The AAGR condenses the medium-term accuracy of the forecast when compared to observed values as it is calculated by taking 2014 as the end year for all samples.

Utilities in our sample expected between 0.6% and 2.6% average growth rates for energy net of demand side resources. Observed growth rates for energy were much smaller, averaging close to zero across our sample of LSEs. About half of our sample shows negative observed AAGR and the ones that show positive AAGR are just above zero. The two exceptions are PacifiCorp, which grew at roughly two thirds of its expected rate, and NW, whose observed growth doubled its forecast growth for energy consumption. By comparing results in tables 3 and 4 we find that generally LSEs with smaller proportional errors will also show more accurate forecast AAGR.

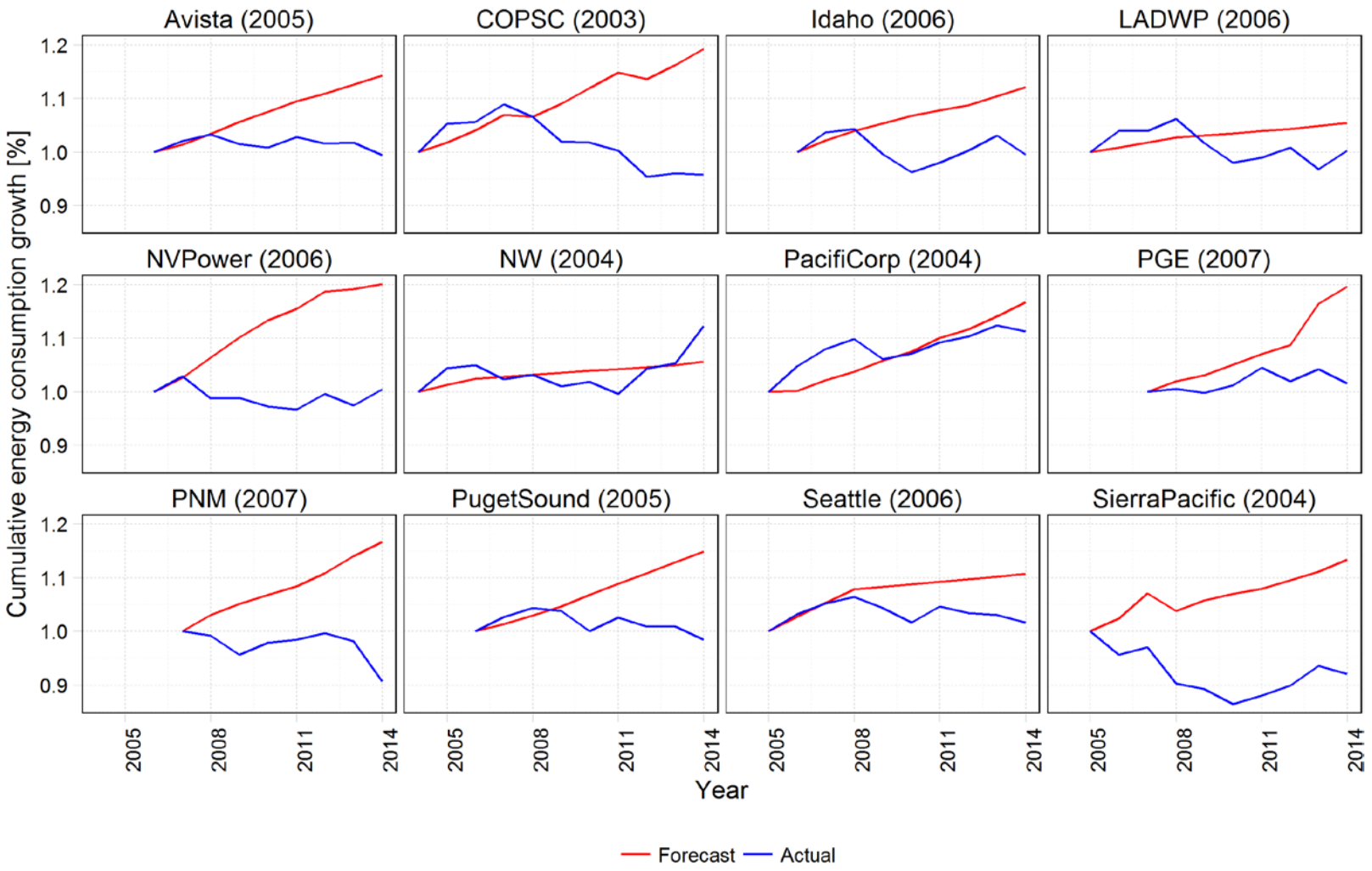


Figure 2 **Forecasted and actual energy consumption growth.**

Table 4 **Average annual growth rate for actual and forecast load**

	Energy AAGR		
LSE	**Base Forecast**	**Actual**	**Difference**
PNM	2.2%	-1.4%	3.6%
PGE	2.6%	0.2%	2.4%
SierraPacific	1.4%	-0.9%	2.3%
COPSC	1.8%	-0.4%	2.2%
NVPower	2.3%	0.1%	2.2%
PugetSound	1.7%	-0.2%	1.9%
Avista	1.7%	-0.1%	1.8%
Idaho	1.4%	-0.1%	1.5%
Seattle	1.1%	0.2%	0.9%
LADWP	0.6%	0.0%	0.6%
PacifiCorp	1.9%	1.3%	0.6%
NW	0.6%	1.2%	-0.6%

5.3 Peak demand

Peak demand forecasts are qualitatively different from energy consumption forecasts, particularly due to their greater sensitivity to weather variation. We find that the accuracy of energy consumption forecasting for a given utility did not necessarily correlate with the accuracy of its peak demand forecasts. In addition, several utilities reported that they were witnessing reduced load factors in their residential load. This means that historical hourly profiles and load factor assumptions may be less informative for peak demand forecast and make the latter more difficult to assess.

We find that several LSEs (COPSC, PGE, and NVPower) see mixed forecasting results — for some years underestimating and for others over-estimating. Other LSEs (Avista, Idaho, SierraPacific, NVPower, and Seattle) consistently over-estimate in the period after the financial crisis, which is symptomatic of a slower-than-expected recovery. Finally, some LSEs (PacifiCorp, LADWP, and PNM) seem to have small systematic under or over-estimation of energy and peak load, but reasonably accurate average growth rate forecasts. This situation occurs with forecasts that underestimate and overestimate actual values in different periods. The average over longer periods of time yields reasonably accurate growth rates, but still shows errors in energy and/or peak load forecast.

As with energy consumption, we extract the implicit growth rates in both forecasted and observed peak demand values and compare them (see Figure 3). We also calculate the Average Annual Growth Rate (AAGR) to facilitate comparison (Table 5). Peak demand growth rates generally show a slowdown after the economic crisis, but not for all LSEs. Seattle, Avista, PGE,

and PugetSound – all in the Pacific Northwest – show a lagged halt in growth compared to other utilities (e.g. COPSC, NVPower, and PNM) whose growth rates reflect an immediate impact. PacifiCorp, LADWP and NW were relatively less affected by the crisis. Peak demand growth rates are more resilient when compared to energy consumption growth rates, which is consistent with the LSEs reporting reduced load factors after the economic crisis.

Table 5 **Peak demand average annual growth rates for forecasted and actual values.**

	Demand AAGR		
LSE	**Base Forecast**	**Actual**	**Difference**
PNM	1.9%	-0.8%	2.7%
COPSC	2.1%	-0.5%	2.6%
NVPower	2.4%	-0.1%	2.5%
Avista	1.8%	0.4%	1.4%
PGE	1.9%	0.8%	1.1%
Idaho	1.4%	0.4%	1.0%
Seattle	1.7%	1.2%	0.5%
PugetSound	1.1%	0.8%	0.3%
PacifiCorp	1.3%	1.3%	0.0%
LADWP	0.3%	1.8%	-1.5%
SierraPacific	1.7%	3.4%	-1.7%
NW	NA	4.1%	NA

Utilities in our sample expected growth rates between 0.3% and 2.4% for peak demand net of demand side resources. Growth rates for peak demand are much higher than for energy. In addition, several utilities reported higher peak demand growth than forecasted, even in the presence of the 2008/2009 crisis. This is consistent with statements in recent IRPs that report worsening[13] (i.e., a reduction) of load factors in residential and commercial customers. We also compare energy and peak demand observed values and find that peak demand forecast error shows much larger variance across utilities. This supports the notion that it is more difficult to forecast long term peak demand than energy consumption.

A comprehensive and exhaustive assessment of load forecast error would require weather normalization of actual values. Unfortunately, we neither have access to the data nor the resources to perform this level of analysis. It is important to note, however, that weather normalization typically has more of an effect on short-term forecast performance. Normalizing

[13] Utilities typically use a negative connotation to refer to load factor reductions, because it means they sell less energy using the same infrastructure putting upward pressure on rates and/or reducing their profits.

weather has less of an impact on long-term forecasts like those analyzed in this paper[14]. Having said that, we examine the historical record for cooling and heating degree-days (CDD and HDD) for the Pacific U.S. region to characterize the weather in the period analyzed. We find that there were warmer-than-average years in 2014 and 2015, but all other years in our period of analysis were considered "normal". For this reason, we believe that our findings would be largely unchanged if we included weather normalization for each observed value and for every LSE. Interestingly, LSEs do not report weather as a primary source of long-term forecast error, which also supports the aforementioned point.

[14] Climate change will impact CDD and HDD in the very long term. However, changes in CDD and HDD will not be large enough in the 10 to 20 year periods used for resource planning to be a relevant source of forecast error.

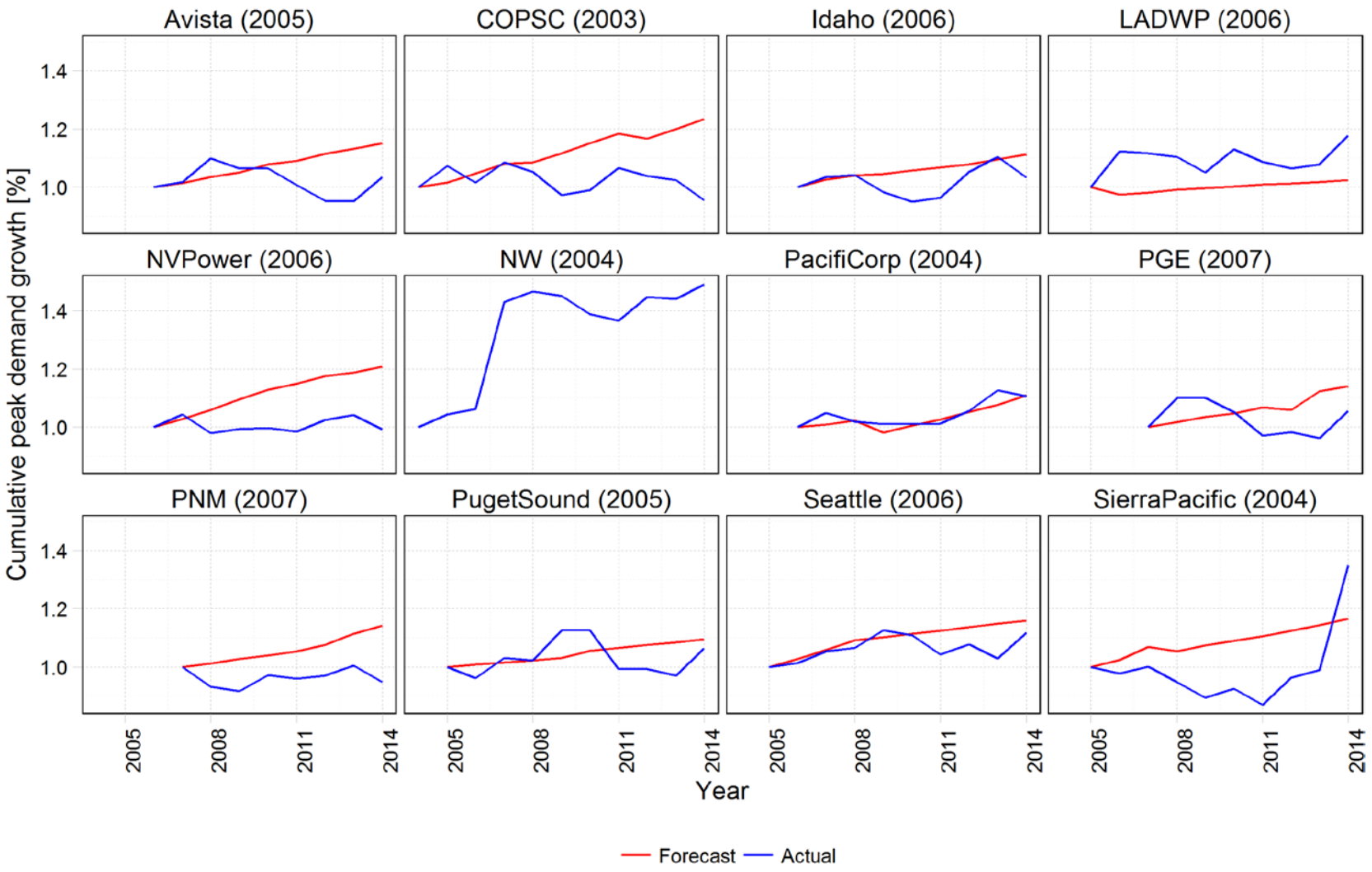


Figure 3 **Forecasted and actual peak demand growth.**

Notwithstanding the general pattern of forecast inaccuracy, we find that forecasts for some LSEs performed significantly better than others, even in the presence of the economic recession. Our preliminary analysis suggests that best performance is not correlated to the size of the utility or to its geographical location. However, given the relative ranking in Table 3, we find that larger utilities have intermediate forecast error. This is perhaps a consequence of having a diverse and large pool of customers that smooths economic impacts on forecast. We also find that LSEs with lower forecast error tend to have fewer sales to industrial customers in proportion to their total sales. This makes intuitive sense: industrial customers are probably the most elastic customer class in relation to economic growth. Their load is hard to forecast and its lumpy nature has a significant impact on forecast results. As some LSEs report in their plans, industrial customers commonly communicate their intention to move in to their service area or to increase load, but they rarely report an impending termination of operations or downsize. This very preliminary assessment suggests that load composition may have an impact on the planning strategy and load sensitivity analyses.

With a few exceptions, we find consistent over-estimation of future energy consumption and peak demand by the LSEs in the resource plans from the mid-2000s. In the following section, we discuss the companies' changes to their forecasts in subsequent IRPs, including the extent to which forecast errors were reduced over the planning periods ending in 2014. In Section 7 we assess into what extent load forecast sensitivities were able to reflect an extreme event like the 2008 recession.

6. Economic forecasts and revisions to load growth forecasts

6.1 Economic forecasts

Long-term energy modeling is unavoidably subject to considerable uncertainty. The forecast errors discussed in this paper might reasonably be considered an example of this fact. At the same time, it would be expected that the continual revision and updating within the IRP process serves to progressively lower these errors, reducing or minimizing their potential consequences for capacity expansion.

Perhaps the most important issue for the present analysis is the U. S. national recession that began in 2008. Although the macroeconomic business cycle is an established phenomenon, predicting the timing and magnitudes of economic downturns remains an inexact process, and moreover the magnitude and duration of the recession that began in 2008-2009 are widely (though perhaps not universally) recognized to have been unusually severe. Thus, despite the *ex-ante* unpredictability of the exact macroeconomic details, ongoing IRP processes would be expected to have, in subsequent years, accounted for dramatically reduced economic activity and its effects on electricity use (along with other influences on load growth subsequent to the year the original forecasts were created).

We examine IRPs and load forecasts for certain years following those in which the above-discussed forecasts were made for a number of the LSEs. We call these IRPs "intermediate" in the context of this analysis since they were produced between the "older" and "recent" ones employed throughout this study (see Table 1). These intermediate IRPs reveal that, while forecasts are of course revised and updated, the LSEs themselves devote varying levels of attention to retrospective examination, evaluation, and correction of their own load forecasts and forecast errors. In some cases, there is not only considerable analysis of this type, but also improvements in forecasting methods in order to obtain greater accuracy. In others, while forecasts are updated, there is little or no retrospective discussion in the documents we examined.

In those cases in which forecast errors are discussed *ex post*, the LSEs as expected highlight reduced economic activity as the key factor for previous overestimation of load growth over the time period in question. In some cases, the effects of demand-side management programs to promote energy efficiency are also cited – that is, as reducing growth more than had been anticipated. As we noted previously, the available documentation is not sufficient to replicate the load forecasts and fully determine the quantitative importance of different inputs. However, in the plans that cite these demand-side effects, they appear to be clearly secondary to (considerably smaller than) those of reduced economic growth.

For example, Avista's planning process demonstrates sustained attention to evaluating and improving load forecasts, and reveals the company's emphasis on the importance of economic growth projections for forecasting electricity use, and on the effects of the recession during the planning period we are examining. In its 2005 IRP, the company states that "employment and population forecasts provide the basis for electric customer projections," which are in turn the basis for its load forecasts. At that time, Avista projected 1.8% average annual customer growth, and 2.1% average annual electricity sales growth, over the twenty –year (2005-2025) forecast period. Similarly, in its 2007 IRP, Avista continued to project average customer growth of 1.8%, and sales growth of 2.0%, over twenty years.

Avista's 2009 IRP noted the slowdown in national and regional economic growth that had begun by that time, but stated that "…the current recession is expected to end by 2011," and projected twenty-year 1.7% average annual growth in both customers and sales. The company's 2011 IRP discusses the continuing effect of slower economic growth on sales, while continuing to assume that the recession would end in 2011. It was not until the 2015 IRP that the company reported that population and employment growth in its service territory had begun to recover.

Similarly, in its 2011 IRP, COPSC discusses the effects of the slowdown that had begun in 2008, including employment declines in Colorado, by way of explaining the slower-than-predicted load growth over the previous several years, while predicting strong economic, population, and employment growth, and hence "recovery" in load growth, going forward through 2018.

Idaho's 2006 IRP contains extensive documentation of the company's methods and models for demographic and economic analysis, including detailed forecast tables of population, employment, etc. in Idaho. By contrast, the 2009 and subsequent Idaho IRPs contain significantly less documentation of this type. They do, however, address the effects of the recession – both the 2009 and 2011 plans state that load growth had been slower than predicted in the previous plan because of the national and service area economic slowdown. The LSE highlights the growth rate in the number of households in its service territory as a key basis for load forecasting. In its 2006 IRP, it projected that the average annual growth rate in this quantity would be 1.7% over twenty years; in 2009, the forecast was 1.3%, and in 2011 1.2%.

In these examples and several others, the pattern appears to be that economic factors contributed significantly to the lower-than-forecast load growth we have discussed above, but that the LSEs continued, over successive IRPs, to predict economy recovery to at least some degree, and therefore a recovery in load growth rates from those in the aftermath of the recession. For most if not all of the LSEs, however, significant economic recovery, and therefore return to higher load growth rates, were not forthcoming for a number of years. Given the LSE's reliance on macroeconomic forecasting services such as Global Insight, this may reflect the fact that economists in general, including forecasters, did not anticipate the very slow and partial recovery, by historical standards, from the recession that began in 2008-2009. Given the considerable apparent impact of economic factors on load growth over the period we are studying, these facts highlight the importance of economic and demographic forecasting in the IRP process, including the *relative* impact of these factors compared to others that influence load growth and are analyzed in the IRP processes.

6.2 Revisions of load growth rates in subsequent forecasts

We can also draw upon the successive IRP updates to examine changes to the load forecasts themselves. For the ultimate purpose of the present analysis – relating load forecasts to capacity expansion – what is of particular interest is the extent to which forecast errors are reduced during the planning periods in which capacity expansion decisions are made. As discussed above, we are focusing on the years up to and including 2014 since that is the most recent year for which estimates of actual load are available from the EIA. Thus, consider a load forecast made in 2005 that extends to 2014 or beyond. Although the forecast may, in retrospect, embody non-negligible errors over the 2005-2014 horizon, updated forecasts made after 2005, but before 2014, might have reduced these errors and thus mitigated their potential impact on capacity expansion.

Examining successive forecasts in this manner shows that, although in some cases errors do decline, for most LSEs they remain non-negligible. Indeed, in most cases we see a sustained over-estimation of load growth-to-2014 even as the year in which the forecast was conducted approaches 2014. Specifically, actual load growth to-year-2014 was in most cases small or even negative as the years-of-forecast approached 2014, but the forecasts themselves continue to

project positive growth at rates that have turned out to be higher than actual rates and in some cases of the opposite sign (negative rather than positive).

This pattern is shown for several LSEs in the following tables. The first is for Avista, and illustrates the format of the information (Table 6). The earlier Avista IRP discussed in this paper is from 2005 (with 2006 being the first forecast year). Avista also produced IRPs in 2007, 2009, and 2011 (with first forecast years corresponding to the IRP years), with its 2011 IRP including a comparative table of these load forecasts. The second column of the table gives the corresponding average annual growth rates of load (energy) from each, calculated from the forecasts' base years *through 2014*. The third column gives the actual growth rates for each period. Thus, for example, the original (2005) IRP projected an average energy load growth rate of 2.35% through 2014; the actual rate turned out to be -0.07%. The most recent (2011) forecast projected a three-year growth rate of 1.62 %, with the actual being -1.11%. This information is displayed graphically in Figure 6.

Table 6 **Avista – Forecasted and actual energy consumption growth rates to 2014**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	2.35%	-0.07%
2007-2014	2.60%	-0.38%
2009-2014	1.78%	-0.41%
2011-2014	1.62%	-1.11%

Figure 6 shows the systematic decline in forecasted growth rates in successive revisions as well as actual energy use by the LSE's customers. There is a very consistent relationship between the growth rate two years before the forecast and the average forecast growth rate.

Table 7 gives similar information for COPSC. In this case, the only LSE forecasts available to us were from 2003 (with 2004 being the forecast base year) and 2011 (with 2012 the base year). Both the projected load growth rate and the forecast error decline from 2003 to the 2011 IRP, but there is again an over-estimate of future loads.

Table 7 **COPSC – Forecasted and actual energy consumption growth rates to 2014.**

Period	LSE-Projected AAGR	Actual AAGR
2004-2014	1.78%	-0.43%
2012-2014	0.81%	0.18%

For Idaho Power (Table 8), forecasts were available from IRPs or plan updates in 2006, 2008, 2009, and 2011. While the error is lower for the 2008 forecast than for the others, there is again a consistent over-projection of load growth.

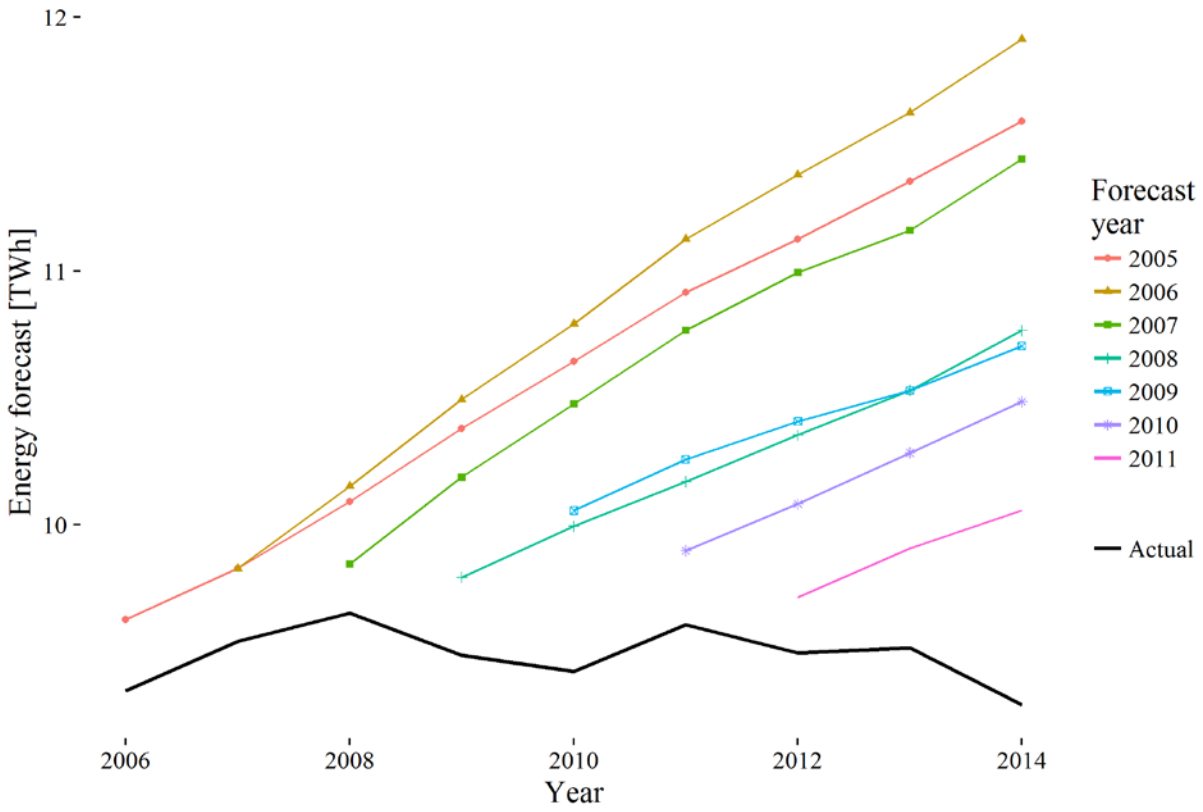


Figure 4 **Intermediate energy consumption forecasts for Avista 2005-2011.**

Table 8 **Idaho – Forecasted and actual energy consumption growth rates to 2014**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.79%	-0.06%
2008-2014	1.57%	-0.77%
2010-2014	2.00%	0.86%
2012-2014	2.12%	-0.35%

In the case of LADWP (Table 9), in addition to its 2006 IRP, short-term growth rates were projected in a 2010 IRP. The table shows the same pattern of reduced but not eliminated over-estimation of growth, which is also present in the case of Nevada Power (Table 10), comparing 2006 and 2009 forecasts (with first forecast years 2007 and 2010).

Table 9 **LADWP – Forecasted and actual energy consumption growth rates to 2014.**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.22%	-0.45%
2010-2014	0.84%	0.56%

Table 10 **Nevada Power – Forecasted and actual energy consumption growth rates to 2014.**

Period	LSE-Projected AAGR	Actual AAGR
2007-2014	2.29%	-0.51%
2010-2014	1.23%	0.28%

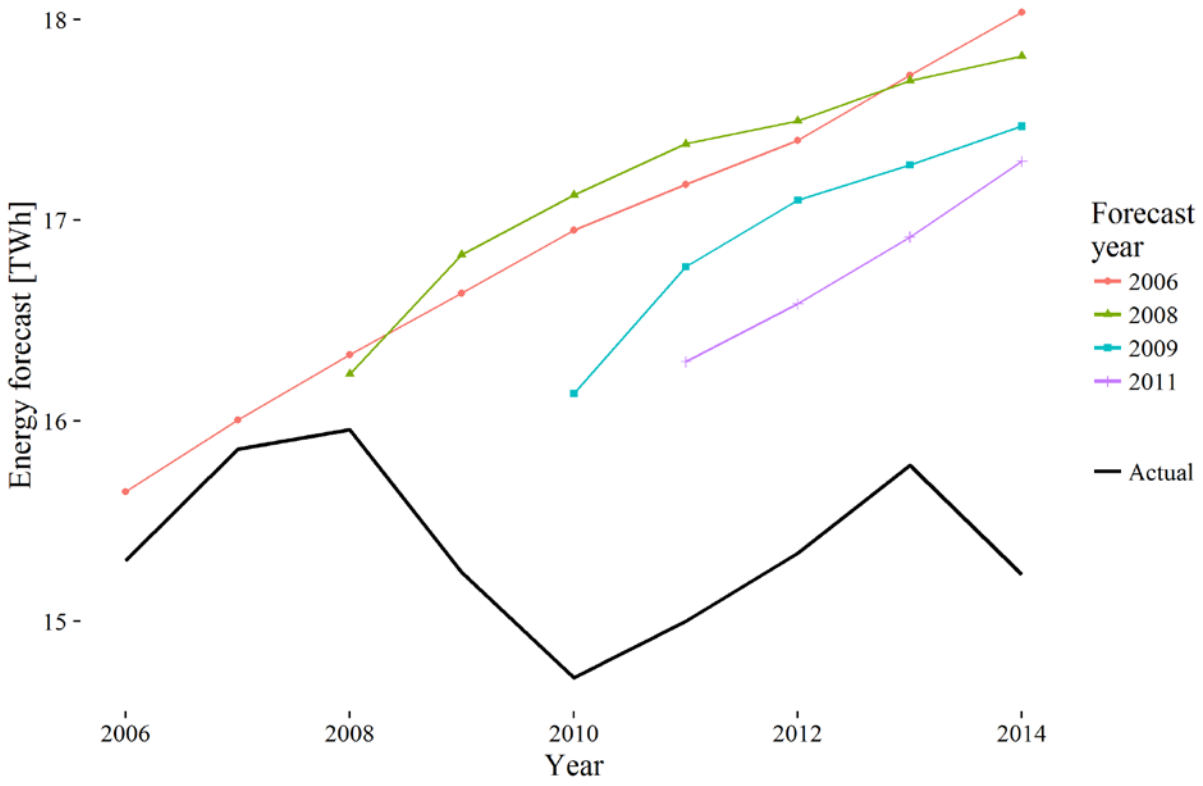


Figure 5 **Intermediate energy consumption forecasts for Idaho 2006-2011.**

Only the previously-discussed 2004 IRP forecast was available for Northwestern Energy (Table 11). In retrospect, the Northwestern Energy forecast under-estimated load growth to 2014. Similarly, as shown in Table 12, PacifiCorp's 2004 IRP forecast (with first forecast year 2006) turned out to be an underestimate. However, the company's forecasts in subsequent IRPs over-estimated growth to 2014.

Table 11 **Northwestern Energy**

Period	LSE-Projected AAGR	Actual AAGR
2005-2014	0.47%	0.74%

Table 12 **PacifiCorp**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.12%	1.47%
2007-2014	2.56%	1.01%
2009-2014	2.40%	0.47%
2011-2014	2.52%	1.63%

Tables 13 through 17 present analogous comparisons for the remaining LSEs in our sample, and show a similar over-estimation of load growth in IRPs over time. With the exception of Sierra Pacific, the forecast errors are increasing from older to newer forecasts.

Table 13 **PGE**

Period	LSE-Projected AAGR	Actual AAGR
2007-2014	1.78%	0.23%
2009-2014	2.10%	0.09%
2012-2014	2.30%	-0.18%

Table 14 **PNM**

Period	LSE-Projected AAGR	Actual AAGR
2007-2014	2.22%	-1.39%
2012-2014	1.72%	-4.62%

Table 15 **Puget Sound**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.75%	-0.19%
2012-2014	1.90%	-1.19%

Table 16 **Seattle**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.52%	-0.19%
2012-2014	1.93%	-0.84%

Table 17 **Sierra Pacific**

Period	LSE-Projected AAGR	Actual AAGR
2005-2014	1.40%	-0.53%
2008-2014	1.44%	0.33%

Overall, while the LSEs continually "course correct" (i.e., update and revise) their load forecasts, there appears to be a general pattern of persistent over-estimation of load growth.

Ongoing forecast adjustment is important and worthwhile, but our analysis reveals there is still systematic error patterns due to the methods employed in load forecasting. In the following section, we explore load growth sensitivities reported in older plans to understand the methods and strategies they developed and planned for to deal with this inevitable uncertainty.

7. Load forecast sensitivities in resource planning

We have shown that LSEs that developed IRPs in the early to mid-2000s observed economic conditions that generally contributed to optimistic load forecasts. While a few utilities have relatively smaller forecast errors—in both energy and peak demand—the majority of utilities evaluated in this study tended to over-estimate these values within their IRPs. The IRP process has evolved to consider the risks due to uncertainty of certain key variables, including future customer load. Accordingly, many LSEs use analytical techniques to measure how robust resource portfolios are to exogenous changes to these key variables. These analysis techniques are classified as scenario-based (i.e., sensitivity) and probabilistic (i.e., stochastic) risk assessments (see e.g. Wilkerson et al. (2014)).

In earlier sections, it was shown that actual load was generally lower than expected load. It follows that there is a risk of excessive capacity being built if expansion plans were not revised after the initial IRP was filed. This risk of acquiring more resources than needed – either by overbuilding capacity or through power purchase agreements – may translate to higher costs to consumers than necessary depending on whether these investments or contracts were actually made and included in the rate base. For this reason, we analyze the low and high load sensitivities from older IRPs to understand whether utilities were required to respond to potential deviations from their base case load forecast and how.

7.1 Review of load forecast sensitivity methods

In this section, we evaluate (i) the method used to create alternative load forecasts; (ii) the results of the load sensitivity analysis, (iii) the strategies developed by LSEs to respond to these alternative forecasts; and (iv) how LSE's methods have evolved from older to more recent plans. Detailed descriptions of load sensitivity methodology and results for each LSE are included in Appendix D and a summary in Table 18 below.

Evaluating the methods used to produce alternative load forecasts is an important step, because these methods reflect utility (and/or regulatory) motivation for considering a wider range of future conditions including alternative population growth, regional economic, and customer consumption scenarios. In the earlier plans, we find that most LSEs use percentiles or deviations from the base forecast as their alternative. In contrast, in more recent IRPs most LSEs are developing comprehensive future settings that reflect the interactions of several different

fundamental variables such as economic and population growth and alternative technology adoption, among others. These scenarios usually analyze joint variation in quantitative variables such as natural gas and electricity market prices as an improved alternative to one-on-one variable sensitivity analysis. While the design of future scenarios remains a challenge, these new approaches should provide a better basis for robust planning processes.

We find three possible methodological approaches for sensitivity analysis of load forecast in older plans[15]. The first is LSEs that simply did not perform any sensitivity analysis, even when estimating alternative load forecasts. The second is LSEs that perform the analysis, but that do not produce an alternative portfolio. The last is LSEs that adjust their preferred portfolio to the new load conditions. The difference between the last two approaches is that the second holds investments as fixed and therefore test the impact of load deviation on operational costs/savings in their portfolios to verify that their preferred portfolio remained as the least-cost solution. In contrast, the third outcome produces an adapted portfolio that can be the basis of an adjustment strategy to alternative load conditions. We find that about half of the LSEs in our sample of older plans either were not required to perform sensitivities or were not required changing their preferred portfolios in light of new load conditions. In more recent IRPs, we find that most of the LSEs that perform sensitivity or stochastic risk assessments also develop new portfolios that are different than their original and preferred base case.

In most cases, reassessment of preferred resource portfolios in response to load forecast sensitivity analysis resulted in drastically different timing and size of resources. We inspect the sensitivity results in older and recent IRP to confirm that inter-scenario utility revenue requirement differences were usually much larger than inter-portfolio revenue requirement differences[16]. In some cases, the inter-portfolio valuation difference was small enough that it could be statistically insignificant. In contrast, several LSEs reported adjustments up to ±20%-40% of capacity under low or high load conditions. Load growth is generally the most important assumption in sensitivity analyses conducted by the utilities in terms of its quantitative effect. It follows that the development of methods to deal with variation in high-impact, uncertain variables—especially load growth—may be more relevant for utilities than the choice of a "preferred" portfolio under a given base case scenario.

[15] It is important to consider that LSEs develop their resource plans subject to the conditions, restrictions, and obligations imposed by the frameworks that regulate them. The reader should not interpret that the presence or absence of certain analyses or method is necessarily a choice of the LSE, but a requirement of the planning rules.
[16] In this context, inter-portfolio refers to the creation and evaluation of several different resource portfolios to find the least cost and lowest risk (i.e., "preferred") portfolio. Inter-scenario refers to the corresponding revenue requirement effects from varying assumptions of key variables including load growth, natural gas prices, capital costs, etc., usually performed as part of the sensitivity analysis.

Table 18 **Summary of load sensitivity methods in older IRPs.**

LSE	Source of alternative forecast	Assessment method	Horizon	Results	Strategy	Change from older to recent IRP
Avista	Economic model; Statistical (Distribution)	Scenarios; Stochastic	Long term for energy, short term for peak demand	Capacity adjustment; timing and resource mix not changed.	React to new information	Quantitative instead of qualitative scenario analysis; improved load model.
COPSC	Statistical (Percentile)	No information	Long term for energy, short term for peak demand	No information	No information	None
Idaho	Statistical (Percentile)	Scenarios	Short term for peak demand	Capacity and timing adjustment	Procure small, flexible resources	Stochastic instead of scenario analysis
LADWP	Statistical (Percentile)	No information	Short term for peak demand	No information	No information	None
NV Power	No information	No information	No information	No information	No information	No information
NW	Market prices elasticity	Scenarios	Short term for peak demand	Operational cost reassessment	No information	Stochastic instead of qualitative scenario analysis
Pacificorp	Statistical (Distribution)	Stochastic	Long term for energy, short term for peak demand	Operational cost reassessment	No information	Add scenario analysis.
PGE	Statistical (Percentile)	Scenarios; Stochastic	Long term for energy, short term for peak demand	Capacity and timing adjustment	Use market purchases/sales as buffer	None
PNM	Statistical (Percentile)	Scenarios	Short term for peak demand	No information	No information	Improved load model
PugetSound	Economic model	Scenarios	Long term for energy.	Capacity adjustment; timing and resource mix not changed.	No information	Only additional scenarios
Seattle	Economic model	Scenarios; Stochastic	Long term for energy	No information	No information	Improved load model
SierraPacific	Economic model	Scenarios	Long term for peak demand	Capacity and timing adjustment	No information	None

The adoption and intensive use of stochastic risk analysis in several recent IRPs is a good step in aligning inter-scenario and inter-portfolio decisions. However, there is still a general absence of methods to produce and follow-up with clear strategies that respond to higher or lower realized load. In one of the few examples of regulatory implementation of adjustment strategies, the Utah Commission requires Pacificorp to produce "resource acquisition paths." These paths transparently lay out responses to specific potential outcomes of relevant variables in the planning process and act as an "extension" of the typical action plan included in most IRPs.

In older or more recent IRPs, most LSEs did not report any type of analysis on the effects that alternative load growth scenarios would have on their planning outcomes. For those plans that did report these analyses, we identify two approaches to deal with this uncertainty: (1) resource flexibility and (2) market transactions. Flexibility refers to the procurement of smaller and quick deployment supply or demand-side technologies to adjust rapidly to new conditions (e.g. Idaho and Avista). LSEs report that they would expedite or defer deployment of these smaller and modular resources in response to higher and lower load conditions than expected, respectively Market transactions pertain to purchases/sales using non-firm transactions as a "buffer" for long-term, structural adjustment due to higher or lower than expected customer load (e.g. PGE)[17]. LSEs report that they would sell their output to the market if load conditions were lower than anticipated and purchase if load was higher.

Both of these strategies have limitations. The focus on flexible resources restricts the types of technologies that would be deployed and reduces opportunities for larger capital intensive projects. The use of market transactions, as suggested by some LSEs, assumes that market purchases are always on the margin, which is not necessarily accurate in all cases. Also, national or global economic performance will jointly affect electricity market conditions as well as load growth. Economic downturn may create surplus on electricity markets due to load contraction and therefore make market purchases more attractive. The use of market purchases or sales as buffers may not recognize this strategy. Finally, relying on market purchases as a strategy for long term adjustment implies coupling electricity price uncertainty with load growth uncertainty. This makes the entire strategy formulation much more complex.

[17] Other LSEs did mention in their IRPs market purchases as a hedging tool for short term supply-demand mismatches, but these market purchases are not discussed within the context of a load sensitivity analysis.

7.2 Quantitative analysis of load sensitivities

In this section, we study the base forecast, the range covered by the high and low load growth forecast estimates, and the actual load[18].

We observe that two LSEs, Northwestern and Sierra Pacific, developed very large "envelopes" around their base forecast that encompassed their actual retail energy sales and obligations (Figures 6 and 7). All other LSEs, including those LSEs with a relatively smaller forecast error, did not produce alternative forecasts that encompassed actual outcomes for energy sales. Most of the LSEs developed symmetrical and narrow forecast envelopes with a low average annual growth rate (AAGR) forecast boundary that was significantly higher than the observed average annual growth rate for energy (see Tables 19 and 20). The preceding is an example of the challenges of producing alternative forecasts that can span a wider range of possible future outcomes. It also reflects the tradeoff between the span of alternative forecasts and the complexity of the strategies to address them: a larger span requires a more sophisticated sensitivity analysis and strategy development.

Table 19 **Average annual growth rate for actual and forecast load, with sensitivities.**

	Energy AAGR			
LSE	**Low Forecast**	**Base Forecast**	**High Forecast**	**Observed**
Avista	0.3%	1.7%	2.9%	-0.1%
COPSC	1.6%	1.8%	2.0%	-0.4%
Idaho	1.5%	1.7%	2.3%	-0.1%
LADWP	-	0.6%	-	0.0%
NV Power	-	2.3%	-	0.1%
NW	-1.7%	0.6%	1.9%	1.2%
PGE	1.2%	2.6%	3.1%	0.2%
PNM	-	2.2%	-	-1.4%
PacifiCorp	1.1%	1.9%	2.1%	1.3%
Puget Sound	1.2%	1.7%	2.3%	-0.2%
Seattle	0.3%	1.1%	1.9%	0.2%
Sierra Pacific	-0.2%	1.4%	2.5%	-0.9%

We also evaluate the performance of alternative peak demand forecasts. The results for the peak demand forecasts are different than the results for the energy forecasts. Observed energy consumption growth was generally less than anticipated, but peak demand growth exhibits mixed

[18] In the case of Pacificorp, which does not provide point estimates for its alternative load growth forecast but a distribution of values, we use the 10th and 90th percentiles as the low and high values, respectively. No alternative energy forecast information was reported for LADWP, NVPower, and PNM, and no alternative peak demand forecast were available for NVPower, NW, PacifiCorp, and Seattle.

results with both over and underestimation of actual peak demand. In addition, in most cases the spread of the forecast envelope is wider for peak demand than for energy (e.g., COPSC, PGE, Puget Sound, and Seattle). This wider spread may reflect the simultaneous consideration of short term (e.g. weather) and long term (e.g. growth) uncertainty in the sensitivity analysis (energy sensitivity only considers long term). Sierra Pacific was the only utility whose forecast envelope consistently encompassed the observed load over time, but it was also the sensitivity with the largest spread (see Figure 6). While a larger spread can effectively encompass many different future scenarios, it also requires a more flexible procurement strategy to alternate between these scenarios.

Table 20 **Peak demand average annual growth rates for forecasted and observed values, including sensitivities.**

	Peak Demand AAGR			
LSE	**Low Forecast**	**Base Forecast**	**High Forecast**	**Observed**
Avista	0.3%	1.8%	2.9%	0.4%
COPSC	1.9%	2.1%	2.5%	-0.5%
Idaho	1.5%	1.7%	2.3%	0.4%
LADWP	-	0.3%	1.1%	1.8%
NVPower	-	2.4%	-	-0.1%
NW	-	NA	-	4.1%
PGE	1.3%	1.9%	2.9%	0.8%
PNM	-	1.9%	2.4%	-0.8%
PacifiCorp	-	1.3%	-	1.3%
PugetSound	0.9%	1.1%	1.8%	0.8%
Seattle	-	1.7%	-	1.2%
SierraPacific	-0.8%	1.7%	2.8%	3.4%

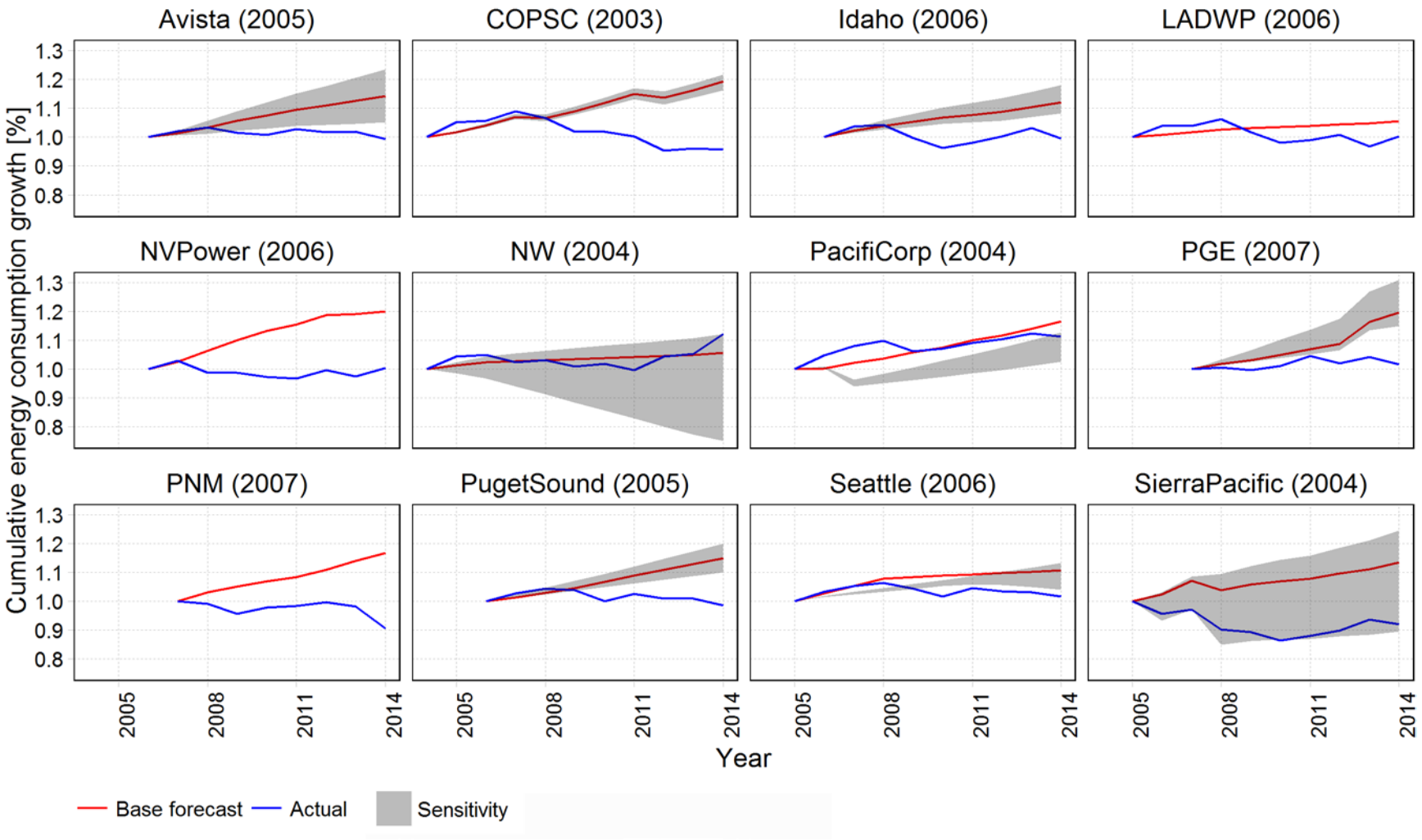


Figure 6 **Forecasted and actual energy consumption growth, with alternative load growth forecasts.**

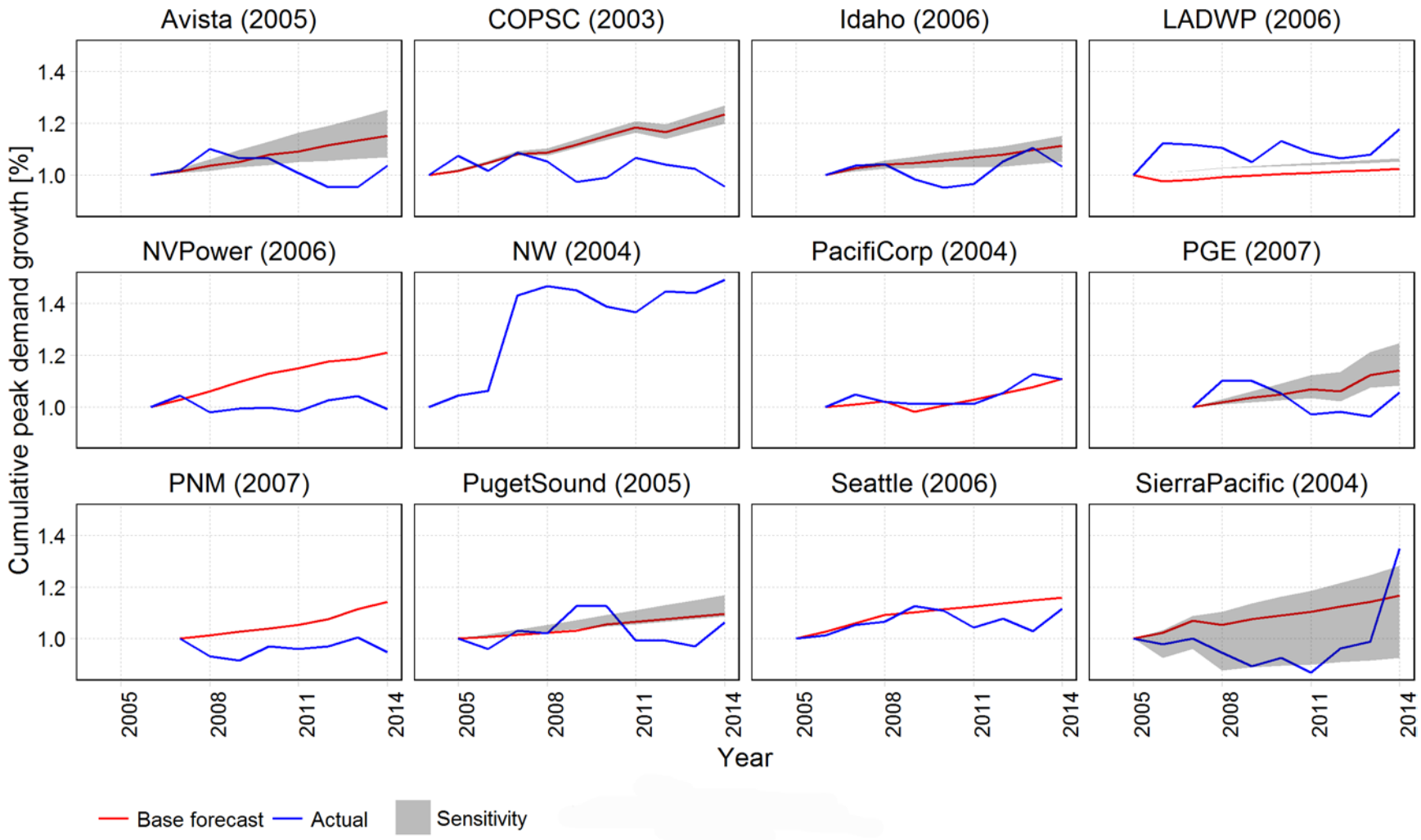


Figure 7 **Forecasted and actual peak demand growth, with alternative load growth forecasts.**

8. Comparison between older and recent plan load forecast methodologies

We compare load forecast methodologies from older and recent plans for two reasons. First, we want to understand whether there is a qualitative relationship between forecast error and adjustments to forecast methodology as a response. Second, analyzing any changes in forecast methodologies helps to ascertain the applicability of our findings to present day planning processes.

Between IRP filing dates, electric LSEs often make adjustments to their load forecasting analysis framework (e.g., mix of customer classes evaluated, makeup of forecast scenarios); choice of variables and analytical techniques (e.g., time-series regression, statistically-adjusted end-use models); and sources of key economic and demographic assumptions (e.g., IHS Global Insight, Inc., EPRI, Moody's Analytics, Inc.). These changes are made in an effort to ultimately improve forecast accuracy in light of (1) evolving market and regulatory conditions; (2) perceived improvements to analytical techniques; and (3) access to more accurate forecast assumptions.

LSEs that implemented procurement decisions based on load forecasts that had larger errors may have had the most incentive to make changes to their forecasting inputs, methods, or both between filing dates. If so, then older and newer IRP forecasting methods can be compared to determine the degree of change between filing dates as a possible response to forecast errors. Figure 8 summarizes the extent of changes made for each of the LSEs considered in this study and the three categories related to forecast methodology described in section 4.

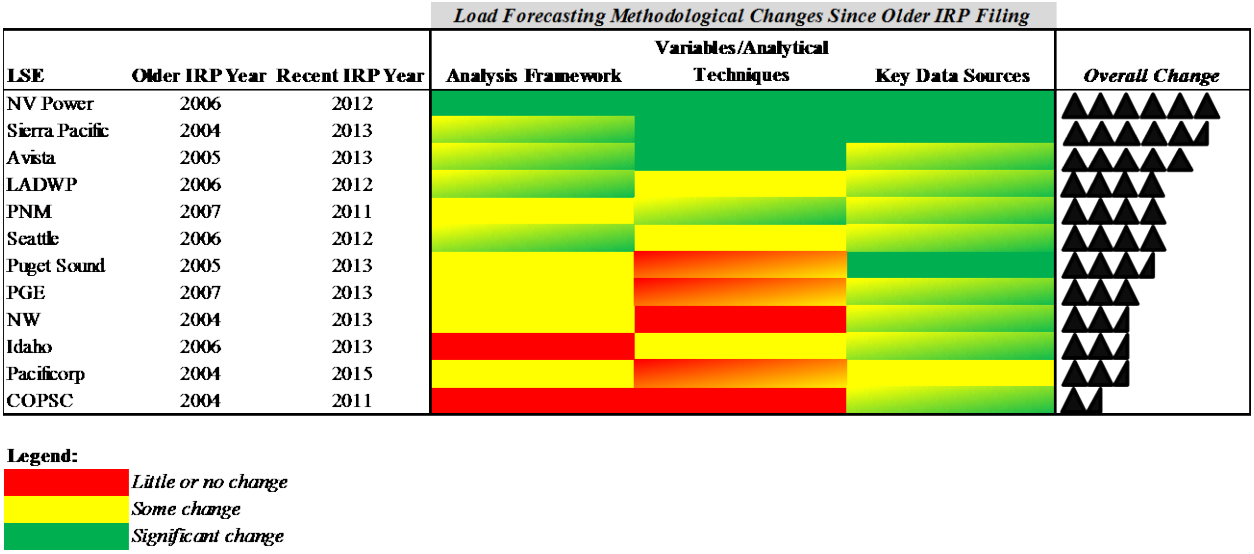


Figure 8 **Load forecasting methodological changes since earlier IRP filing.**

Overall, nearly all of the LSEs considered in this study found new data sources for key modeling assumptions (e.g., population, regional economic activity). Half of the LSEs made changes to all three components of their load forecasting methodology (analysis framework, technique, and source of data). Some LSEs made significant changes to load forecasting-related variables and

analytical techniques, but a larger share of LSEs made very small or no changes within this specific category. Most LSEs did not make significant changes to the analysis framework between filings. NV Power, Sierra Pacific, and Avista made the most significant methodological changes between plan filings. Colorado Public Service Corporation, PacifiCorp, and Idaho Power made the least number of changes.

8.1 Changes to analysis framework

Changes to load forecasting frameworks typically involved incorporating additional sets of load forecasts based on a wider range of growth scenarios (NV Power, PGE, LADWP, PacifiCorp, Seattle City Light) or changing the mix (or number) of customer classes considered in the analysis (Seattle City Light, LADWP, Avista, Puget Sound, NV Power). In some cases, LSEs assumed that future load growth was lower than the low growth rate reported in the earlier plan. Sierra Pacific and Puget Sound Energy are two examples of LSEs which made changes to customer classes to reflect the importance of new types of customers including transportation (i.e., electric vehicles).

8.2 Changes to variables and analytical techniques

Many changes to load forecast variables and analytical techniques involved migrating from one modeling technique to another. For example, Sierra Pacific switched from an econometric/time-series based modeling approach to a statistically adjusted end-use (SAE) modeling approach. Conversely, Avista indicated that their load forecasting methodology is "undergoing significant restructuring [and] involves using an Auto Regressive Integrated Moving Average (ARIMA) technique" (i.e., time-series based econometric modeling). Other LSEs simply incorporated new variables including those used to capture adoption of electric vehicles (Idaho Power, LADWP, PNM, Seattle City Light, Avista, NV Power) or saturation of energy efficiency initiatives (PGE, NV Power, Idaho).

8.3 Changes to sources of key externally-produced assumptions

Perhaps most interestingly, there was a significant consolidation in the source of external data used in the production of LSE load forecasts. A number of LSEs began using IHS Global Insight, Inc. in their earlier plans, specifically, for demographic and regional economic growth estimates, and the majority of the LSEs now do so (COPSC, Sierra Pacific, PGE, NV Power, Avista, PacifiCorp, and Seattle). A smaller number of LSEs rely on Moody's Analytics, Inc., local/state/federal government agencies, or post-secondary educational institutions for regional demographic and economic assumptions. It is not immediately evident why this consolidation took place. The Electric Power Research Institute (EPRI) and Itron, Inc. were consistent sources of assumptions about customer responses to prices and end-use saturation and efficiency projections.

One utility planner, who wished to remain anonymous, indicated the following about third-party forecast performance and how commissions may view these vendors:

> "[Third-party forecast provider redacted] county-level forecasts consistently over-stated the speed and strength of the economic recovery in our service area. I believe this was a significant factor in the observed over-forecasting. The heavy reliance on [redacted third-party forecast provider] by [redacted] and other utilities may be connected [with] the increasing usage of [redacted third-party forecast provider] by state governments for the purpose of forecasting state revenues. That is, the adoption of [redacted third-party forecast provider] by state governments may have been viewed as a "seal of approval" by the utilities regulated by the same states. From the utilities' perspective, if [redacted third-party forecast provider] was good enough for the states' revenue models, then it may have been easier to argue that [redacted third-party forecast provider] was also good enough for their load models. In addition, I have noticed that many commission staff members often "signal" that they trust third party forecasts more than the utilities' in-house forecasts. If this preference is strongly signaled, then utilities may be inclined to adopt third party forecasts to deflect any future criticism."

The overall reliance on a few number of third-party forecast providers may be one reason that forecasts were consistently over-estimated by other LSEs as well. This finding implies that planners should consider supplementing third-party forecasts or conducting alternative economic forecasting to minimize forecasting error that can be attributed to outside parties.

8.4 Evolution of forecasting methodologies and variables

This comparison established that there have been few if any changes in forecasting methodologies over the past decade or so that would limit the applicability of our analysis of older plans to understanding present-day practices by the LSEs. The types of variables used in the load forecasting process have essentially not changed and, while some LSEs have changed their analysis techniques, they have switched to techniques that were already in use in earlier plans and have not, apparently, adopted or developed new techniques. We are confident that our findings and suggestions are very much applicable to current and future resource planning processes.

There is a general convergence across utilities in the forecast modeling technique and the sources of economic data. In relation to the former, we find that both time series and cross sectional regressions have become the typical analytical framework to produce base case forecasts for energy and peak demand. LSEs incorporate many variables in their models, but they also acknowledge that population and economic growth are the main drivers in their load forecasts. These regression methods inevitably rely on historic information that may tend to reproduce past economic, social, and regulatory trends.

Regarding the sources of data, we observe a convergence of sources for the basic economic and social-demographic forecasts, which can have an important implication. Regulators have increasingly been using benchmarking approaches to compare regulated utilities for purposes

that range from rate setting to informational (Jamasb and Pollitt, 2000; Lowry and Getachew, 2009). Similarly, regional planning entities typically compile forecasts from utilities under their purview to determine aggregate load growth and expansion scenarios. Utilities report that forecasts are very sensitive to a small set of variables, namely economic and population growth. When LSEs use the same source for economic variables, their forecast errors become jointly determined and correlated. The benefit of benchmarking and aggregation that may average out errors in forecast is diluted with this convergence of sources. In addition, the use of proprietary forecasts adds an undesirable layer of obscurity to a process that was designed to encourage transparency and involvement from the public. When utilities use proprietary data, they are typically not allowed to make public the underlying values used in their load forecasting models, which may preclude scrutiny and evaluation of their results.

In the following section we assess the potential performance of load sensitivity methodologies and strategies by comparing forecast and actual load against planned and procured resources.

9. Comparing load forecasts and resource planning & procurement

We have established a general trend of load over-estimation and varied methods to analyze and formulate strategies to deal with load growth uncertainty. In this section we verify whether resource procurement was adjusted to actual lower load growth levels and how load sensitivity analysis described before may have informed this adjustment. It would be expected that supply-side capacity expansion would be greater than peak demand growth, particularly because supply-side resources that are not dispatchable (e.g., wind and solar) may not contribute to meet peak demand or may contribute a limited amount to resource adequacy. Hence, we perform two analyses: one comparing load to nameplate resource capacity and the other comparing load to available-at-peak resource capacity. We report the available-at-peak analysis in this section and the nameplate capacity in Appendix E.

We de-rate the nameplate capacities for both planned and actual supply-side resources based on average "capacity available at peak" ratios from the resource plans we study. In this case, de-rating means we estimate capacity available at peak as a fraction of nominal nameplate capacities, which are usually larger. We assume that coal and combined cycle natural gas plants have a firm equivalent capacity of 85%; geothermal, peaking natural gas units, and nuclear have 100% equivalent capacity; PV, generic renewables, and wind resources have a 10%[19] equivalent capacity and unknown resources[20] a 40% equivalent capacity. We check that these assumptions

[19] A recent paper estimates that utilities in the West assign a larger capacity credit for solar of 30%-50% (Mills et al., 2016). We use a 10% because it was a common reported value for most utilities in the early 2000s. In any case, there was little solar PV planned and procured for our sample of utilities, so its capacity credit has a minor effect in the results.

[20] In many cases LSEs that rely on market purchases in their resource plans do not know a priori what type of technology will produce the capacity they expect to purchase. These are labeled "unknown resources" for our purposes and apply only to planned resources. The 40% figure is roughly the ratio of firm to non-firm products purchased by utilities.

are reasonable by comparing the planned expansion to the forecast peak demand. Aggregate peak demand forecast of ~9 GW by 2014 was quite consistent with a planned expansion of roughly ~12 GW in the same period (Figure 9, right panel). This is a result we expect: meeting peak demand growth is a fundamental constraint of IRP. With these assumptions we then estimate that "at-peak" procurement was ~11 GW, a fifth of those in PPAs and the remainder in self-builds (Figure 9, left panel). Over the narrower 2007-2014 period, the at-peak capacity acquired was over 8 GW. This value should be compared against less than 1 GW aggregate growth in peak demand in the same period.

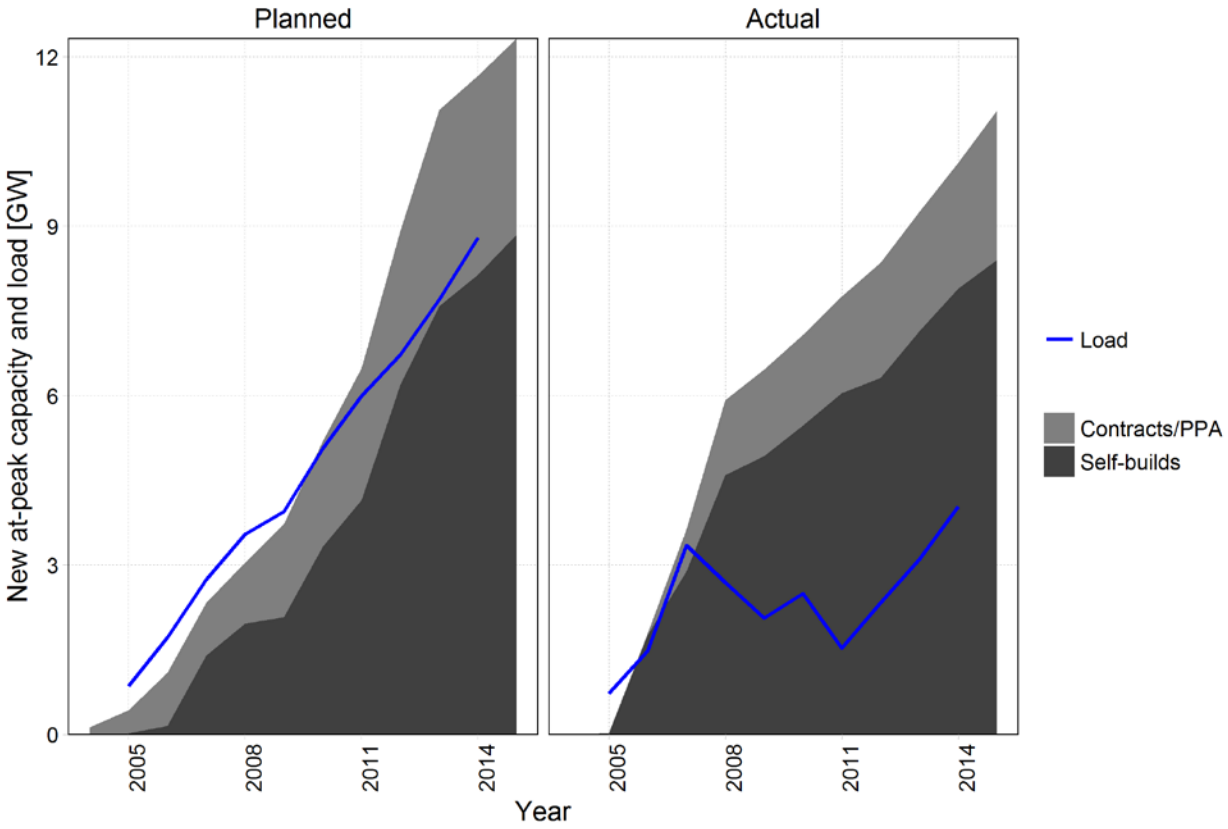


Figure 9 **Planned and actual (procured) at-peak capacity with forecasted and observed peak demand.**

Retirement of plants may explain in part the excess procured capacity. For our sample of utilities, we find that generation units totaling approximately 2.5 GW of at-peak capacity were retired in the 2005-2014 period. We also find that over 80% of the retirements accrue to three specific LSEs (LADWP, Nevada Power, and COPSC). An analysis of individual LSE load-procurement balance is out of the scope of this study, but is included in our follow-up paper.

Then, retirements can account for about a third of the excess procured capacity compared to actual load[21].

The actual response of LSEs to lower-than-expected load conditions stands in contrast to their reported results and strategies from the load sensitivity exercises described in section 7. Many LSEs found important changes in resource acquisition timing and capacity when applying alternative load forecasts in their IRP modeling exercise. We do not see this reflected in practice, as most procurement capacity and timing decisions are consistent with base case expansion even under actual low load outcomes. The fact that procurement is persistently aligned with load forecasts is in line with the findings in section 6, with LSEs systematically forecasting positive and higher growth rates than informed by very recent observed values. Our cursory review does not support that load sensitivities had an important role to inform procurement decisions because we do not see adjustment strategies reflected in quantities procured. Acquired resources seem to generally follow the original planning, regardless of the short and medium term performance of load forecasts and of actual energy sales and peak demand.

10. Summary and conclusion

We have quantitatively and qualitatively analyzed the methods for and performance of load forecasts for a set of electric integrated resource plans created by utilities in the Western U.S., and examined load sensitivities and the relationships among load forecasting, planning, and resource procurement. A comparison of forecasts to actual energy use and peak demand reveals that all but one of the LSEs overestimated energy consumption growth over planning periods beginning in the mid-2000s and ending in 2014, and that eight of the eleven LSEs that forecast peak demand also over-estimated this quantity. In addition, we find that most of the LSEs that had the highest expected growth rates also experienced the lowest actual – in some cases negative - demand growth.

Furthermore, examination of forecasts from more recent IRPs indicates a persistent overestimation of demand growth over planning periods up to year 2014, even in the presence of much slowed actual growth, for most of the LSEs in our sample. A number of the utilities highlighted the effects of the national recession that began in 2008-2009 to explain this phenomenon. Over time, the utilities did adjust their forecasts of projected load growth downward in response to lower-than-expected demand, but continued to overestimate. The IRP documentation suggests that for most of the LSEs, to a significant extent this apparently reflected an expectation that the national and regional economies would follow a historical pattern of relatively quick recovery from the recession. Thus, most utilities expected that load growth

[21] We recognize there are other concomitant factors that could influence resource procurement that we do not analyze here. For example, changes in renewable portfolio standards (RPS) targets may force larger adoption of renewable resources, or unanticipated earlier retirement of plants or termination of contracts may require larger capacity additions.

would recover as well. The actual, slower-than-expected economic recovery thus contributed to over-estimates of future load in more recent IRPs.

We find some correlation between forecast methods and complexity, and the accuracy of forecasts. In addition, the LSEs that had the most accurate peak demand forecasts were also among the most conservative in terms of their expected peak demand growth. LSEs with relatively more complex models had less forecast error than those that employed simpler models. Among the more complex techniques, Statistically-Adjusted End-use (SAE) models did not perform much better than other load forecasting methods and models. These results suggest that, among the LSEs we studied, there may be small marginal benefits to greater model complexity. There are structural reasons that may also explain the relative accuracy of load forecasts. For example, we find that utilities with a larger share of industrial load in their mix generally had larger forecast error. We believe that this may be caused by the highly elastic and lumpy nature of industrial customer load as well as the difficulty in predicting entry and exit of industrial customers from a LSE service area. This suggests that industrial loads should be modeled and risk assessed separately from the remaining loads to understand utility-level impacts of large adjustments.

Load sensitivity analysis is an important component of risk assessment and management in IRP. In the context of our study, it is especially important because strategies derived from load sensitivity analysis may adjust and impact resource plans as new information comes in. Over time, we find that LSEs have improved the breadth and sophistication of their sensitivity analysis of load forecasts. However, we find that both older and more recent IRPs generally lack an adaptive component that details how utilities would respond in practice were subsequent actual values of critical input variables—like load — to correspond to those studied in these sensitivity analyses rather than to those assumed in "base cases." More importantly, we find that load variation from the base case produces differences on revenue requirement for an LSE that are much larger than the differences in revenue requirement from the resource portfolios that are designed and compared to select the “preferred” one.

For our overall sample of utilities, we find that aggregate (pooled across utilities) planned and actual capacity expansion levels were generally consistent over the time period of our study. However, in aggregate, actual resource procurement were not closely aligned with observed changes in load. Actual capacity additions were partially attributable to retirements of existing plants, which accounted for about 2.5 GW for several utilities. It is possible that this apparent over-procurement reflects LSEs seeking to avoid resource adequacy problems by hedging against rapid rebounds in load that may exceed their ability to procure unforeseen required firm capacity. The volatility in observed peak demand growth rates and the quick recovery of some LSEs’ peak demand provide evidence in favor of this.

We find that load forecast methodologies have not changed significantly in the past fifteen years, although there is evidence in recent plans of inclusion of potential structural change drivers such

as distributed energy resources and electric vehicles. We did find that LSEs with more changes in their forecasting methodologies had previously had relatively greater forecast errors. This suggests an active effort to at least react to forecast error, although we do not have evidence that these changes lead to improvements in accuracy. In general, we believe that our findings of load forecast performance and relationship to procurement over our analysis period are applicable to current planning and procurement processes even if we studied decade-old plans.

To our knowledge, this is the first quantitative and comparative retrospective study of energy and peak demand forecasts by LSEs. This paper has been primarily descriptive and exploratory and as such our findings indicate several key topics for further research to better understand and to explain our results.

First, was over-optimism regarding resumption of economic growth following the severe recession of 2008-2009 the fundamental reason for the persistent over-estimation of load growth during the study period? If so, what does this imply about the role of economic growth assumptions in overall IRP processes and the strategies that may be derived from load sensitivity analyses? In addition, how much of this over-estimation may be due to under estimation of energy efficiency gains?

Second, what were the reasons for the divergence between load forecasts, on the one hand, and procurement, on the other? What were the differences in resource mix, timing, and market transactions between planning and procurement, and what the potential impact of these differences is?

Third, what is the balance between a better forecast to select the right portfolio and a better strategy to switch between portfolios and adjust to changing environments under a budget constrained planning process? What shape should these strategies take and what improvements would they have on the planning and procurement processes?

These questions, particularly the second, will be the topic of our second paper, in which we will investigate the connections between IRP and procurement processes in depth. We hope that both this paper and its sequel will contribute to the goal stated in the Introduction, of furthering the understanding of IRP among a diverse group of stakeholders, and contributing to the further evolution and improvement of planning methods and outcomes.

11. References

ABB-Ventyx, 2016. Ventyx Velocity Suite Energy Mapping Software. ABB-Ventyx, Boulder, CO.

Aspen, E3, 2008. Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California.

Avista, 2013. 2013 Electric Integrated Resource Plan. Avista Utilities Inc.

Avista, 2005. 2005 Electric Integrated Resource Plan. Avista Utilities Inc.

COPSC, 2011. 2011 Electric Resource Plan, CPUC Docket No. 11A. Xcel Energy.

COPSC, 2004. 2003 Least-Cost Resource Plan. Public Service Company of Colorado.

EIA, 2016. Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files [WWW Document]. US Energy Inf. Adm. URL https://www.eia.gov/electricity/data/eia861/ (accessed 3.18.16).

English, M.R., Schweitzer, M., Schexnayder, S., Altman, J.A., 1995. Energy efficiency advocacy groups Factors affecting their influence on DSM and IRP. Util. Policy 5, 55–63. doi:10.1016/0957-1787(95)00014-Q

Eto, J.H., 1990. An Overview of Analysis Tools for Integrated Resource Planning.

Foley, A.M., Ó Gallachóir, B.P., Hur, J., Baldick, R., McKeogh, E.J., 2010. A strategic review of electricity systems models. Energy, The 3rd International Conference on Sustainable Energy and Environmental Protection, SEEP 2009 35, 4522–4530. doi:10.1016/j.energy.2010.03.057

Goldman, C.A., Comnes, G.A., Busch, J.F., Wiel, S., 1993. Primer on Gas Integrated Resource Planning (No. 34144). Lawrence Berkeley National Laboratory, Berkeley, CA.

Hadley, S., Hirst, E., 1995. How integrated resource planning for US electric utilities affects shareholder interests. Util. Policy 5, 37–45. doi:10.1016/0957-1787(95)00012-O

Hirst, E., 1994. What constitutes a good integrated resource plan? Util. Policy 4, 141–153. doi:10.1016/0957-1787(94)90008-6

Hirst, E., 1990. Assessing Integrated Resource Plans Prepared by Electric Utilities [WWW Document].

Hirst, E., 1989. Integrated resource planning at electric utilities: The planning process. Eval. Program Plann. 12, 213–223. doi:10.1016/0149-7189(89)90032-3

Hirst, E., 1988. Regulatory Responsibility for Utility Integrated Resource Planning (No. ORNL/CON-249). Oak Ridge National Lab., TN (USA).

Hirst, E., Carney, J., 1978. Ornl Engineering-Economic Model of Residential Energy Use (No. ORNL/CON-24). Oak Ridge National Lab., TN (USA).

Hirst, E., Goldman, C.A., Hopkins, M.E., 1991a. Integrated resource planning - Electric and gas utilities in the USA. Util. Policy 1, 16. doi:10.1016/0957-1787(91)90045-7

Hirst, E., Lin, W., Cope, J., 1977. Residential energy use model sensitive to demographic, economic, and technological factors. Q. Rev. Econ. Bus.

Hirst, E., Schweitzer, M., Yourstone, E., Eto, J., 1991b. Technical competence of integrated resource plans prepared by electric utilities. Resour. Energy 13, 39–55.

Hyndman, R., 2006. Another Look at Forecast Accuracy Metrics for Intermittent Demand. Foresight Int. J. Appl. Forecast. 43–46.

Idaho, 2013. 2013 Integrated Resource Plan. Idaho Power.

Idaho, 2006. 2006 Integrated Resource Plan. Idaho Power.

Jamasb, T., Pollitt, M., 2000. Benchmarking and regulation: international electricity experience. Util. Policy 9, 107–130. doi:10.1016/S0957-1787(01)00010-8

Kahn, E., 1995. Regulation by Simulation: The Role of Production Cost Models in Electricity Planning and Pricing. Oper. Res. 43, 388–398.
LADWP, 2012. 2012 Power Integrated Resource Plan. Los Angeles Department of Water and Power.
LADWP, 2006. 2006 Integrated Resource Plan. City of Los Angeles - Department of Water and Power.
Lowry, M.N., Getachew, L., 2009. Statistical benchmarking in utility regulation: Role, standards and methods. Energy Policy 37, 1323–1330. doi:10.1016/j.enpol.2008.11.027
Mills, A., Barbose, G.L., Seel, J., Dong, C., Mai, T., Sigrin, B., 2016. Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning. Lawrence Berkeley National Laboratory, Berkeley, CA.
Mitchell, B.M., Park, R.E., Labrune, F., 1986. Projecting the Demand for Electricity (Product Page).
Mitchell, C., 1992. Integrated resource planning survey: Where the states stand. Electr. J. 5, 10–15. doi:10.1016/1040-6190(92)90077-K
NASEO, 2013. Review of Utility Integrated Resource Plans and Electric Vehicle Load Forecasting. National Association of State Energy Officials.
Nelson, C.R., Peck, S.C., 1985. The NERC Fan: A Retrospective Analysis of the NERC Summary Forecasts. J. Bus. Econ. Stat. 3, 179–187. doi:10.2307/1391589
NVPower, 2012. 2013 Integrated Resource Plan. Nevada Power Company.
NVPower, 2006. 2006 Integrated Resource Plan (2007-2026). Nevada Power Company.
NW, 2013. 2013 Electricity Supply Resource Procurement Plan. NorthWestern Energy.
NW, 2004. Electric Default Supply Resource Procurement Plan. NorthWestern Energy.
Pacificorp, 2015. 2015 Integrated Resource Plan.
Pacificorp, 2005. 2004 Integrated Resource Plan. Pacificorp Inc.
PGE, 2014. 2013 Integrated Resource Plan. Portland General Electric Company.
PGE, 2007. 2007 Integrated Resource Plan. Portland General Electric Company.
PNM, 2011. 2011-2030 Electric Integrated Resource Plan. Public Service Company of New Mexico.
PNM, 2007. 2007 Electric Resource Plan. Public Service Company of New Mexico.
PugetSound, 2013. 2013 Integrated Resource Plan. Puget Sound Energy.
PugetSound, 2005. 2005 Least Cost Plan. Puget Sound Energy.
Rosekrans, S., Kirshner, D., Marnay, C., 1999. Issues in electricity planning with computer models: illustrations with Elfin and WASP. Util. Policy 7, 201–219. doi:10.1016/S0957-1787(99)00002-8
Sanstad, A.H., McMenamin, S., Sukenik, A., Barbose, G.L., Goldman, C.A., 2014. Modeling an aggressive energy-efficiency scenario in long-range load forecasting for electric power transmission planning. Appl. Energy 128, 265–276. doi:10.1016/j.apenergy.2014.04.096
Schweitzer, M., Hirst, E., Hill, L.J., 1991. A look at the resource portfolios of 24 electric utilities. Electr. J. 4, 38–45. doi:10.1016/1040-6190(91)90097-D
Seattle, 2012. 2012 Integrated Resource Plan. Seattle City Light.
Seattle, 2006. 2006 Integrated Resource Plan. Seattle City Light.
SierraPacific, 2013. Triennial Integrated Resource Plan. Sierra Pacific Power Company.
SierraPacific, 2004. 2004 Integrated Resource Plan. Sierra Pacific Power Company.

Sioshansi, F.P., 1992. Special Issue Clearing the utility marketsDemand-side management and environmental externalities: Ramifications on utility resource planning. Util. Policy 2, 320–329. doi:10.1016/0957-1787(92)90012-8

Wilkerson, J., Larsen, P., Barbose, G., 2014. Survey of Western U.S. electric utility resource plans. Energy Policy 66, 90–103. doi:10.1016/j.enpol.2013.11.029

Willis, H.L., Northcote-Green, J.E.D., 1984. Comparison Tests of Fourteen Distribution Load Forecasting Methods. IEEE Trans Power Appar Syst U. S. PAS-103:6.

Wilson, R., Biewald, B., 2013. Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project and Synapse Energy Economics.

Wilson, R., Peterson, P., 2011. A brief survey of State IRP Rules and requirements (Prepared for the American Clean Skies Foundation). Synapse Energy Econmics Inc.

12. Appendix A – Adjustments to data

We adjust the monetary values from both plans and actual data to express them in real 2014 dollars and allow meaningful comparisons. We use the Gross Domestic Product implicit price deflator based on data from the Bureau of Economic Analysis (Table 21)

Year	GDP Deflator Index	% Change from 2014
2000	81.89	27%
2001	83.75	25%
2002	85.04	24%
2003	86.74	22%
2004	89.12	20%
2005	91.99	17%
2006	94.81	14%
2007	97.34	11%
2008	99.25	9%
2009	100.00	9%
2010	101.22	7%
2011	103.31	5%
2012	105.21	3%
2013	106.93	2%
2014	108.69	0%

Table 21 **GDP deflator used to adjust monetary costs to real 2014 dollars.**

13. Appendix B – Demand forecast methodologies

The following table provides details on demand forecast methodologies for the older resource plans. We identify the framework or general rules required for forecasting, the variables and methods used, and the sources for the data.

LSE	Year	Framework	Variables and methods	Sources for data
COPSC	2004	• They project native load and firm wholesale requirements. They are required by law (LCP rule 3060(b)) to estimate high, base, and low forecasts. • Classes include residential, commercial, industrial, large industrial, public authority, street lights, interdepartamental, and wholesale/resale customers. • Energy and demand are forecasted similarly, with an added variable in demand to capture specific weather-driven peak events. • High and low estimates are created by modifying economic growth and weather variables. They essentially use the third quartile instead of the median for high and the first quartile for low.	• Statistically-Adjusted End-Use (SAE) model. • Residential Customer number (CN) comes from housing stock forecasts. Use-per-customer (UPC) composed from saturation (unknown source) and utilization for cooling, heating, and base use. The latter are simulated from electricity price, household income/size, and CDD/HDD/LightHours respectively using exogenous elasticities. UPC is regressed based on these estimates and monthly company data, using monthly fixed-effects. Implementation is methodologically unclear. • Commercial/Industrial CN methodology is not provided. UPC similar to residential. Saturation based on annual energy intensity (kWh/sqf) trends. Utilization simulated from electricity price, GSP, and CDD/HDD/LightHours. • Large industrial customer sales are forecast based on historical data, market trends, and customer input.	• Demographic and economic: Center for Business and Economic Forecasting, Inc. • Cooling, heating, and base use: internal using data from 1991. • Elasticities for residential utilization: EPRI's REEPS model. • Saturation trends: EPRI's COMMEND model.
NW	2004	• Not clear what load they project, but they do create high, base, and low forecasts. • Classes include small (<50 kW) and large (two tiers, <5MW and >5MW) customers.	• Their approach is econometric, but does not show an end-use approach. They rely on weather and customer number as main explanatory and forecasting variables. • Small customer: they regress consumption to average annual customer count, HDD,	• MT population forecast provided by NPA Data Services, Inc. and made available through MT Census and Economic Information Center. • U.S. economic growth, income

LSE	Year	Framework	Variables and methods	Sources for data
		• Their forecast methodology seems to point to energy forecasting rather than load. They actually do not provide the latter. • They use recent (<5 year old) data to model monthly and hourly consumption patterns. • Low load estimate created by assuming large customers switch to other provider. High load assumes that users with choice (under deregulation) return to NW because default supply price is lower than retail.	CDD, and tariff rates for the past 23 years (1980-2002) to establish historic coefficients. Weather variables and average customer count are independent variables that exhibit a consistent relationship to usage. • Large customer: <5MW is estimated based on rolling five year average of usage plus adjustments for any expected changes based on customer communication; >5MW receives more detailed analysis and communication to determine future levels. • "There is little evidence in the 23 years of data gathered which shows that electricity price changes have an impact on total electric consumption"…."implies that price elasticity of demand for electricity is zero." (p.57). They provide several explanations for this. • They adjust results by DSM.	projections, etc. came from U.S. Economic Projections (U.S. Dept of Commerce). GDP, population, and income projections assumed are included on pages 15-25 of the "Book 2 document"
Sierra Pacific	2004	• Sierra Pacific forecasted peak load and energy out to 2024. They are required by law (NAC Chapter 704) to estimate high, base, and low forecasts. • They predict sales for each of their customer classes and state combinations (CA and NV). Larger customers (GS-3, GS-4 classes) are forecast individually. • Low load case anticipates a "slight downturn in the economy", less population growth (95% base case	• Customer number forecasting by tariff type using an ARIMA model with 1st/12th order autoregressive terms and dummy variables for certain years. • Rates: future rates are forecasted to assess price-elasticity effects. • Cross-price elasticity: they estimate non-statistically significant or negative natural gas/electricity cross-price elasticity. • Use per customer: for non-individual analysis they regress UPC in terms of twenty-year average monthly HDD/CDD, wind speed (if significant), population growth, and historical sales. For large	• CPI from Global Insight's US Economic Outlook. • Population forecast was internal, but a 2001 regulatory decision forced Sierra to use the Nevada State Demographer's. (p.8-9). Sierra thinks this forecast is too low and it seems they created a hybrid. • Hourly loads from EPRI's HELM model.

LSE	Year	Framework	Variables and methods	Sources for data
		confidence interval), and fewer customers. 0.07%/0.24% growth for the summer/winter peak. • High load case assumes more customers, greater population growth (95% base case confidence interval), and a stronger economy. Summer and winter peak growth of 2.85%/2.88%, respectively. • They expect "no major technological changes, such as electric automobiles" (p.9) to affect end-uses of electricity. • They acknowledge recent changes in their seasonal peak due to larger NV growth compared to CA. • Very similar to process used in 2001 IRP.	customers they perform one-on-one estimations for 5-year growth and replicate this result for the next 15 years. • They find population growth is the primary driver of load growth. • Base summer and winter peak loads are expected grow ~1.81-1.83%. Base case energy is expected to grow 1.55%. Manufacturing (3.27%) and residential (2.69%) are expected to grow the most and mining (-1.38%) and industrial the least (-0.19%) (Volume 1, p. 5). • Hourly peak load forecasts were estimated using HELM model (designed by EPRI), which allows utilities to estimate hourly load projections given individual load shapes for each sector. HELM produces loads without losses so losses are incorporated later. • They do not adjust results by DSM, arguing its effect were "of minimal impact upon the system" (33)	
PGE	2007	• Forecast reference, high, and low scenarios with normal weather conditions. High and low are based on base case growth plus/minus 1 standard deviation. This translates into 1% increase/decrease in growth from the base case. • They report median peak load values. • PGE expects to turn from winter to summer peaking in the next 15-20 years.	• Fundamental factors: economy, immigration, life expectancy, and business environment, particularly high tech sector. • Expect higher commercial load, lower residential load, and uncertainty in industrial customers. • They face opt-in/opt-out customers under retail competition. Their strategy is to acquire resources for 1/3 of existing eligible opt-out customers and find the rest on the short- term market. There is no formal forecast for returning/leaving customers.	• No information on sources of data.

LSE	Year	Framework	Variables and methods	Sources for data
		• "Overall demand has always rebounded to grow over time based on macroeconomic and fundamental drivers." (p.40)	• No information on their forecasting models.	
NV Power	2006	• Produce only an expected or base case forecast. • They apply weather normalization their winter and summer historical peak data.	• Econometric models (not SAE) separate for each customer class. Forecast sales, customers, and residential retail rates. • Explanatory variables include CDD/HDD, real retail rates (residential only), monthly/seasonal fixed effects, total residential customers (non-residential only). • Residential: Sales per customer from 1979-2005. -10% elasticity for retail rates as result. Use dummies for year > 2001 (reduction in usage), and 1st/12th order autoregressive terms. • Number of customers: Regress number of residential customers by population from Clark County and a 1st order autoregressive term. CN for other classes are regressed from this residential customer number estimate. • Large general service: Only use CDD/HDD to explain ~90% variation. • Retail rates: They expect 24% increase in real retail rates from 2004 to 2006 and then remain flat. Their forecast is internal and no details are provided.	• Weather data for CDD/HDD for Las Vegas from NOAA. • Population forecasting is very important for them. They retained Univ. Las Vegas, who used a general equilibrium economic and demographic model developed by Regional Economic Models, Inc (REMI) specifically for Clark County for 2005-2035. See p.34 of App2-1 for population predictions. A quick review shows they were off by ~20% on a total population basis or they expected 3 times more growth than actually happened by 2013.
Puget Sound	2005	• Forecast an expected, high, and low scenario. Main difference is GDP growth at 3%, 3.6%, and 2.6% respectively, in addition to lower inflation/higher productivity for high scenario	• They forecast billed energy sales, customer number, system peak load for electricity and gas, and hourly load profiles. • Sales = UPC * CN; the later are estimated through regressions based on historical data from 1990 to 2003. They manually	• They do not mention most sources of data besides their internal sales and load information. • Economic and retail rates forecast from "May 2003 US Forecasts"

LSE	Year	Framework	Variables and methods	Sources for data
		(inverse for lower). • Customer classes include residential, commercial, industrial, street lights, and resale. • Minor methodological changes from 2003 LCP, including higher weather resolution data and spatial load growth estimates. • They create very complex functional forms that rely heavily on lagged operators. I believe there is an important risk of inaccuracies from propagating errors through the functional form. • They generally expect lower growth than historical results.	adjust these estimates (see below). They mention several end-uses, but they don't use them as explanatory variables. • UPC: Regression by class and month in terms of retail rates (includes lags), HDD/CDD, demographic variables (income, household size, population, employment, growth, building permits), monthly dummies. • CN: Regression by class and month based on same demographic variables and monthly dummies. Population and employment are primarily used. • Residential: semi-log functional form, with long lags in rates and demographic variables. They estimate -0.19 price elasticity. Manual adjustments include expected conservation, fuel switching, and tariff switching. • Other sectors: Double log form, also use lags in explanatory variables. Estimate -0.16/-0.19 price elasticity for Comm/Ind respectively. Manual adjustments include expected conservation, fuel switching, and tariff switching. • Peak load is estimated based on regressing hourly peak MW on monthly sales for residential and commercial, and also interacting weather sensitive portions of load with temperature measurements and monthly dummies. Very complex regression. • Hourly demand profile was based on HELM for 2002, but replaced now with a regression of hourly load (1994-2004) on	prepared by Global Insight. Expect growth between 2.9% and 3.6%. • Hourly temperature comes from NOAA observed data at Seattle airport. • They also use a set of account-specific assumptions about certain customers starting or closing their service.

LSE	Year	Framework	Variables and methods	Sources for data
			hourly temperature (1950-2003). They use lags on loads and linear/squared temperature variables, plus an autoregressive term and holiday dummies.	
Avista	2005	• Prepared medium, high, and low forecasts, under the suggestion of the Technical Advising Committee. Main determinant is population growth changes, roughly double growth for "high" and no growth for "low". • They generally refer to residential and commercial classes, although they sporadically mention specific customers (Boeing, Fairchild Airforce Base).	• "Key driver of the electricity customer market is population growth" (p.1-4). • 1998-2004 retail sales grew 1.2%, but they forecast 2.1% for 2005-2025. • Price elasticity estimates: residential -0.15, commercial -0.10. Cross price (NG) elasticity at 0.10 for all classes, and income elasticity at 0.75. These come from own estimates. They don't expect an impact on forecast. • Their language suggests they use regression analysis, but there is no evidence of the functional form or method in the plan itself or the formal appendices. • Slides from stakeholder meetings reveal they do include also weather through CDD/HDD using "96% of Normal" in base forecast (2 s.d.). Electric price forecasts are simply assumed to grow at certain %, although these may be results of the Aurora model runs.	• National/County employment and population forecasts from Global Insight, from March and June 2004 respectively.
Idaho	2006	• Create six load forecasts. The low has 90% probability of being exceeded, while the high 10%. The medium case is the median. All these are estimated under normal weather. They further develop their median forecast by considering normal, 70th, and 90th percentile weather impacts. The growth forecasts bound the	• They use regressions for UPC, with different variables. It seems they use a SAE for peak load only, but they do not use the term and their explanation is very qualitative. They extensively use different percentiles throughout their analysis. • "Weather conditions are the primary factor affecting the load forecast on the hourly, daily, weekly, monthly, and seasonal time horizon. Economic and demographic	• Economic 2006 forecast developed by Idaho Economics, based on a national and regional economic activity forecast by Global Insight. • Electricity price increases (they explicitly say that) are modeled internally, while gas prices are from Global Insight.

LSE	Year	Framework	Variables and methods	Sources for data
		others. Base forecast grows 1.9%/yr, low at 1.5% and high 2.4%. • Base forecast is median growth with 70th percentile weather impact. Their monthly hourly forecast for peak load uses 95th percentile weather. • They analyze residential, commercial, irrigation, and industrial classes. They individually analyze three large customers and their firm sales contracts, making assumptions about their continuity. • They include losses in their estimates.	conditions affect the load forecast over the long-term horizon." (p.29) • Peak loads are regressed from temperature (HDD/CDD/GrowingDD), space heating saturation, A/C saturation, historical average load and precipitation, For large customers, peak load is based only on historical load. • Mention that "changes in relative fuel prices can have significant impacts on the future demand for electricity" (App.A-p.4). However, they don't estimate or show elasticities. • Residential:CN directly forecast from expected household growth. UPC expected to decline, regressed from HDD (winter), CDD (summer), "trends", and rates. Sales = UPC * CN. No information on functional forms or what "trends" are. • Commercial: CN estimated from residential CN. UPC identical to residential, as well as sales. • Irrigation: Expect increase in CN, but reduction in UPC, for zero growth. Only qualitative arguments given. • Industry: Develop 16 regression models, one for each economic activity group. They regress historical sales from historical employment for each group, and forecast using the employment projections. For larger customers the procedure is similar, with additional one-by-one adjustments. • Adjust sale forecasts by expected DSM levels from prior year plans.	
LADWP	2006	• Forecasts for six classes:	• They use employment and personal income	• LADWP purchases a

LSE	Year	Framework	Variables and methods	Sources for data
		residential, commercial, industrial, intradepartmental, streetlight and Owens Valley. • They sensitivize their forecast for different temperatures. They use different temperature percentiles to model alternative peak load forecasts. • Include historical losses.	data as proxies for local GDP. • Res, comm, and ind sales are forecasted using GLS. They regress historical sales against demographic, economic, weather and electric price variables, with additional dummies for specific events. • Net energy load is projected from sales regression using historical monthly allocations and historical losses. • Peak demand is based on a regression of historical hourly demand against temperature bins and apply this elasticity to a forty-year mean peak day temperature. They project peak demand using the same growth rate as sales. • Monthly allocations are based on historical monthly load factors applied over the sales forecast. "To forecast load for each hour of the year, we use the Loadfarm algorithm developed by Global Energy." (p.B-3) • They do not discount DSM because they treat it as a resource, but acknowledge that some of this growth will not be realized.	demographic and economic forecast of Los Angeles County from the Los Angeles Modeling Group of the UCLA Anderson Forecast Project. • The Los Angeles County Forecast provides time series data for various demographic and economic statistics beginning with year 1991 and continuing through the forecast horizon. • LADWP also reviews the State of California Department of Finance demographic forecast for population data. • LADWP purchases a construction forecast from McGraw-Hill Construction service. • Weather data is collected from three NOAA stations. • Internal information includes historical sales, billing cycles, budget, and rates.
PacifiCorp	2004	• "The load forecast that is used in the IRP is updated every two years and is a 20-year hourly forecast of expected loads." (43). Prepared in March 2004. They include historical/future DSM in their projections. • They project a single forecast for their four classes. • They also add losses, separately by each retail class.	• "Near term forecasts rely on statistical time series and regression methodologies while longer term forecasts are dependent on end-use and econometric modeling techniques." (App I p.127) • Near term (at most 3 years): They forecast UPC and CN per state and class: res, com, street lights, and irrigation. CN "relies on weighted exponential smoothing statistical techniques formulated on a twelve-month moving average of the historical number of	• County and state-level economic and demographic forecasts provided by Global Insight, in addition to state office of planning and budgeting sources. • No reported sources for their engineering estimates on appliance usage or for the weather data.

LSE	Year	Framework	Variables and methods	Sources for data
			customers." (I-127). More weight is given to recent observations. • They use a very simple "time-trend" analysis for short term UPC, regressing consumption in time. Industrial customers are forecasted on a case-by-case basis; they don't provide the methods. • Long term: statistical model with several explanatory variables: price elasticity (elec and fuels), economy, conservation, appliance/building replacement. They also forecast employment, population, and income for Pacificorp's states. "Employment serves as the major determinant of future trends among the economic and demographic variables used to "drive" the long-term sales forecasting equations" (I-129). These variables are obtained from Global Insights consultants. • They find electricity price elasticity of 0.10 (absolute value) in internal econometric study. • Residential demand forecast models several structural variables (inhabitants, fuel price, income, structure type) and includes 14 energy end-uses (appliances and space/water heating) with their saturation expectation. They use a CDA or engineering estimates for the use per appliance, and multiply by estimates of saturation and housing stock to estimate consumption. They run separate analysis for new/old homes and single/multi/mobile families. • Commercial is similar to residential, with 7	

LSE	Year	Framework	Variables and methods	Sources for data
			end-uses and 12 commercial activities, but use sqf instead of housing stock. • Industrial they regress "industrial production indexes for the specific industry [on] the relative prices of electricity and natural gas." They break this class in 9 industry categories. • Hourly forecast are created from regressions of historical behavior against weather variables, temporal variables (day/week/season)	
PNM	2007	• Forecast retail loads, existing firm wholesale customers, and transmission/distribution losses (~11%). Special stipulation (Case 3137) requires that only wholesale contracts before 2002 to be included. • There are high/low forecasts in the Appendix that are mentioned in the Sensitivity analysis. They adjust energy and peak load by ±1.5% to create alternative scenarios.	• There is almost no information about the methods they use, what variables they incorporate, and how they derive their estimates. • Key drivers in peak load forecast are CN, higher AC use on homes, and construction/house size (due to low interest rates). They also forecast energy and CN. • Residential: CN * UPC. Expect 2.3% growth on CN and 1.2% on UPC. • Commercial: CN * UPC. Expect 1.7% growth on CN and 2.2% on UPC. • Firm wholesale: City of Gallup use a "statistical" method and City of Navopache a historical projection. Other firm customers use specific methods.	• No source information.
Seattle	2006	• Forecasts do not include any programmatic conservation, a statement of their consideration of DSR as supply resources. They actually make an effort to remove underlying conservation from their load forecast. • Forecast for 9 customer sectors:	• The only variable information is that "The load forecast is based on forecasts of several key economic and demographic variables, primarily employment and the number of households in the service area" (p.13). • Create correlations between historical load for each customer sector and "selected	• "Dick Conway and Associates produces the economic and demographic series for SCL's service area" (App p.48) • Besides internal sales and consumption data, there are no other external information requirements.

LSE	Year	Framework	Variables and methods	Sources for data
		residential, commercial, government, food, metal, stone, aerospace, ship building, and other manufacturing • Develop low, base, and high forecasts with 0.3%, 1.2%, and 1.9% growth, respectively. • As other hydro-based LSEs, they compute joint load-hydro probabilities to understand the chances of drought with high demand concurrently occurring.	economic and demographic variables" (App p.48). Main drivers are number of households and of employees for several customer categories. Mention that "equations are estimated for each sector" without further detail of technique/method. • As many others, qualitatively describe their service territory and trends. • For peak load they analyze distributions of historical peak load, not clear what for. • Do not expect increase in UPC for residential sector (App p.50). They do expect commercial load to drive growth.	

14. Appendix C – Changes in load forecast methodologies from resource plans.

The following table includes details on changes in demand forecast methodologies from the older to the recent resource plans (see Table 1). We identify the framework or general rules required for forecasting, the variables and methods used, and the sources for the data.

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
COPSC	2004	2011	• Framework has not significantly changed since earlier plan (see table above for details about framework)	• Variables and methods have not significantly changed since earlier plan (see table above for details about variables and methods). • Elasticities for sales forecasts continue to be inferred from ERPI's residential end-use model (REEP) and EPRI's COMMEND model: -0.2 price and income for residential; 0.6 GSP and -0.2 price for commercial/industrial.	• Demographic and economic growth estimates now come from IHS Global Insight, Inc. (earlier source was Center for Business and Economic Forecasting, Inc.)
NW	2004	2013	• Newer plan provides both energy and load forecasts (earlier plan did not provide peak load forecasts) • Framework does not appear to have significantly changed since earlier plan (see table above for details about framework).	• Variables and methods have not significantly changed since earlier plan (see table above for details about variables and methods). • Both plans note that the price elasticity of demand is assumed to be zero. However, the newer plan notes that a Smart Grid Demonstration Project will help the company monitor	• County-level population forecasts are a product of Regional Economic Models, Inc. (REMI) via the Montana Census & Economic Information Center (CEIC) (earlier source for population projections came from NDA Data Services, Inc. via the MT CEIC) • Future economic conditions are not included in newer IRP

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
			• Base peak load forecast is median probability of occurrence; assumed that low and high loads are determined using similar process as noted in earlier plan.	price elasticities in the future.	forecast (earlier source noted that economic growth, income, etc. came from U.S. Department of Commerce)
Sierra Pacific	2004	2013	• Adjusted load to account for impact of EV/PV adoption, DR, DSM, and system losses (earlier plan indicated "no major technological changes, such as electric automobiles" to affect end-uses of electricity; results were also not adjusted for DSM because these effects were—"of minimal impact upon the system")	• Began using Statistically Adjusted End-Use Model in 2009 (earlier plan used in ARIMA model to forecast number of customers with $1^{st}/12^{th}$ order autoregressive terms and dummy variables for certain years). • Not clear how different new SAE method is from old method, because older method did involve predicting end-use per customer based on weather, population growth, sales, etc. • Newer plan forecast database includes: "historical billed sales, number of customers, population and economic data, prices, weather conditions and historical end-use saturation and efficiency trends" • Implicit reference to use of elasticities in both plans:	• Regional demographic and economic growth estimates now come from IHS Global Insight, Inc., but the State of Nevada's State Demographer high population forecast was also used in some way (earlier source used a hybrid of an internal population forecast and the State Demographer). • Itron, Inc. data was used to determine end-use saturation and efficiency projections. Sierra Pacific also conducted residential appliance saturation surveys to supplement information provided by Itron, Inc.

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
				newer plan indicates that "Real household income impacts residential average usage per customer; older plan indicates that there are non-statistically significant or negative natural gas/electricity cross-price elasticities • Weather forecasts in both plans based on average over last 20 years	
PGE	2007	2013	• Added another set of high and low demand forecasts based on much higher (lower) growth scenarios—plus and minus two standard deviations (earlier plan had base and +/- 1 standard deviation high/low growth scenarios) • In addition to high/low scenarios, weather-driven load changes are stochastically-modeled per 2007 requirement from OPUC Order 07-	• Weather forecasts in both plans based on average over last 15 years • Both plans have little or no information about the regression model used to forecast demand. • Fundamental assumptions impacting load forecasts: weather (temperature); economic outlook; population forecast; industrial customer trends (earlier plan fundamental factors include: economy,	• Little or no information was included about data sources in 2007. In 2013, PGE uses local economic/demographic data from Oregon Office of Economic Analysis, national data from IHS Global Insight, Inc. and California employment forecasts from the California Employment Development Department • Weather is the most important driver of load forecasts, but no information about where weather data came from.

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
			002 (IRP guidelines).	immigration, life expectancy, and business environment, particularly high tech sector) • Continue to expect higher commercial load, lower residential load, and uncertainty in industrial customers, but also indicated that there would no load growth in street lighting due to conversion to LED-based lamps. • Ran 100 iterations to capture the random variations in hourly weather-driven load • No mention of elasticities except that customer price elasticities were used in determining DR potential	
NV Power	2006	2012	• Newer plan includes low, base, and high case energy and peak demand forecasts (earlier plan only contained a base case forecast) • Newer plan contains	• Newer plan explicitly accounts for end-use saturation and efficiency projections in the residential and commercial sales forecast models (earlier plan does not appear to incorporate end-	• Demographic growth estimates now come from combination of IHS Global Insight, Inc., Center for Business and Economic Research (CBER-UNLV), and Las Vegas Convention and Visitors Authority. Other economic

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
			reorganization/consolidation of the types of customer classes modeled: residential, small C&I; large C&I; public street and highway lighting; and public authority (earlier plan modeled residential; general service; large general service, which includes six subclasses; large general service-1; public authority; and street lighting).	use or efficiency projections in the load forecast methodology) • Newer plan accounts for "residual DSM savings (not embedded in the sales models), small net metering (solar PV and wind), DR reductions, and plug-in electric vehicle, plus any other significant changes in expected demand not captured by the estimate forecast models" (earlier plan did not explicitly indicate that any of these factors were accounted for in the forecast). • Newer plan forecasts using statistically-adjusted end-use models (SAE) (earlier plan was based on time-series econometric modeling); weather-normalization technique also appears to have changed due to switchover to SAE • Elasticities used in modeling are -0.15 (price), 0.2 (income), 0.2 (households) (earlier plan	information—historical and future—comes from IHS Global Insight, Inc. (earlier source of all data was CBER-UNLV and Regional Economic Models, Inc.) • Elasticities came from EPRI's Residential End-Use Energy Planning System model (REEPS) • NV Power now utilizes Itron, Inc. by incorporating their end-use saturation and efficiency projections in their load forecasts.

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
				used -0.10 for price elasticity)	
Puget Sound	2005	2013	• Modeling framework and number of load forecast scenarios does not appear to have significantly changed since earlier plan (see table above for details about framework). • One change is the inclusion of a new class of customers: transportation (earlier plan customer classes include residential, commercial, industrial, street lights, and resale). • Continue to use very (most) complex functional forms that rely heavily on lagged operators, quadratic terms, and a mix of data transformations (log-log, semi-log, etc.).	• Variables and methods have not significantly changed since earlier plan (see table above for details about variables and methods). • Not surprisingly, time-series data used to develop load profile and other components includes data up through 2011 (earlier plan, for example, was based on temperature and load data through 2003 and 2004, respectively) • Puget Sound acknowledges that customers are adopt electric vehicles, but that the "initial adoption of EVs and plug-in hybrids would not have significant effects on PSE's energy needs or distribution system" • Not clear how transportation class of customers is modeled differently from other customer classes described in the earlier plan. • No specific mention of elasticities (earlier plan had extensive information about	• Use wider variety of national/state/local sources to develop demographic and economic growth estimates including: (1) Moody's (for U.S. econ./demographic forecast); (2) Washington State Employment Security Department, Bureau of Economic Analysis, Bureau of Labor Statistics, Office of Financial Management (state of Washington); (3) Puget Sound Economic Forecaster; and (4) Washington State Economic and Revenue Forecast Council (earlier source for U.S. data was IHS Global Insights, Inc. and little information provided about other data sources)

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
				elasticities assumed in load forecasting)	
Avista	2005	2013	• Avista prepares low (0.5% employment growth average), medium, and high (2.5% employment growth average) load forecasts (earlier plan assumed 0% growth for low and double medium growth for high) • Customer classes specifically include: residential, commercial, industrial, and street lights (earlier plan referred to residential and commercial)	• "Avista's load forecasting methodology is undergoing significant restructuring. The restructuring involves using an Auto Regressive Integrated Moving Average (ARIMA) technique. ARIMA improves the modeling of economic drivers involving population, industrial production, income levels and energy prices to predict long-term energy demand. This new methodology will improve forecasts in 2015 IRP" (earlier plan did not provide detailed information on method, but regression analysis was suggested) • New plan contains significant detail on equations used to project population, HDD/CDD, etc. • Avista notes that estimating elasticity is "problematic and that they "lack sufficient data to estimate elasticity values for its service area" (earlier plan had detailed price	• Wider variety of sources used to project demographic and economic growth including: (1) IHS Global Insight, Inc.; (2) U.S. Federal Reserve; (3) Bloomberg; (4) U.S. DOE-EIA; and (5) internal forecasts (earlier source listed was IHS Global Insight, Inc.) • "The load forecast uses 30-year monthly temperature averages recorded at the Spokane International Airport weather station through 2012."

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
				elasticity estimates). • Considered use per customer with and without EV adoption (earlier plan did not explicitly indicate how EV adoption would impact load forecasts).	
Idaho	2006	2013	• Similar framework to earlier plan where load forecast scenarios are based on alternative probabilities of occurrence weather and economic activity will be different than the median assumptions • Newer plan average load growth rate is assumed to be 1.1% annually with peak load growing 1.4% under all three scenarios (earlier plan had higher growth rates)	• Newer plan considers impact of increased adoption of EV • All other variables and methods appear to be similar or the same as what was reported in the earlier plan • Newer plan appears to contain even less information (when compared to older plan) describing forecasting methods, models, and techniques • Newer plan contains implicit reference to price elasticity, but no explicit information on what that elasticity value is ("Longer term, the effect of economic recovery is tempered in the forecast by higher retail electricity price assumptions that incorporate estimates of assumed carbon legislation, which decreases the average load forecast") • EE impact is included in	• The economic forecast is now based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc. The national, state, metropolitan statistical area (MSA) and county economic projections are tailored to Idaho Power's service area using an in-house economic database (earlier source of economic data came from Idaho Economics based on national/regional economic activity forecasted by IHS Global Insight, Inc.).

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
				sales forecast, but DR is excluded and treated as an resource option	
LADWP	2006	2012	• Newer plan presents alternative 1-in-10 peak load and energy forecasts by the date the forecast was made (earlier plan has base case peak demand; hot weather peak demand forecasts; and single energy forecast) • Newer plan contains a seventh customer class: plug-in electric vehicles (earlier plan includes forecasts for six customer classes: residential, commercial, industrial, street lighting, Owens Valley, and Intra-departmental)	• Variables and methods (e.g., generalized/ordinary least squares regressions)—with exception of plug-in electric vehicle forecasts from third-party—appear to be similar or the same as what was reported in the earlier plan	• Similar sources for population/economic forecasts (e.g., California Department of Finance, McGraw-Hill Construction forecast, State of California Economic Development Division L.A. County Forecast), but expanded use of (1) electric vehicle penetration forecasts from California EV coalition; (2) Los Angeles Port Authority electrification forecasts; and (3) housing forecasts from the city of Los Angeles. Weather information continues to be provided by NWS/NOAA, but another weather data source was added in the new IRP (Los Angeles Pierce College)
Pacificorp	2004	2015	• Newer plan includes three different load forecast sensitivities: low (low economic growth from IHS Global Insight and low industrial growth in Utah/Wyoming); base; and high (high	• Newer plan specifically refers to using statistically-adjusted end-use model for residential class customers—ITRON provided a spreadsheet model to predict future changes in energy efficiency; industrial forecasts are provided	• Company now uses both ITRON load forecasting software systems and state-by-state population and economic information provided by IHS Global Insight, Inc. (earlier source listed was state-level information from IHS Global Insight, Inc.)

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
			economic growth from IHS Global Insight and high industrial growth in Utah/Wyoming) (earlier plan includes single load forecast)	directly by customers; commercial forecasts are made by using regression analysis techniques forecasting sales using historical sales, non-manufacturing employment, and weather (earlier plan refers to process similar to SAE for residential, commercial, and other customers but technique is not explicitly called SAE; industrial customers are forecasted in close consultation with actual customers) • Newer plan does not directly mention price elasticities (earlier plan indicates that price elasticities of demand are 0.10)	
PNM	2007	2011	• Newer plan projects load under three scenarios: (1) low; (2) base/mid; and (3) high. Difference between older and newer plan is that newer plan uses low and high trajectories based on information provided by	• Newer plan considers impact of increased adoption of EV—including conducting sensitivities around the assumed uptake • Both plans have little or no information about the regression models and techniques used to forecast demand (newer plan:	• Little or no information was included about data sources in 2007. In 2011, PNM identified the University of New Mexico Bureau of Business and Economic Research as the source of population forecasts. Information about electric vehicle penetration was

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
			the University of New Mexico and IRP Working Group (earlier plan simply assumed that low was 1.5% lower than mid and high was 1.5% higher than mid forecast)	"PNM uses a statistical-based time series modeling to prepare its load forecasts…includes three parts: a forecast of retail loads, a forecast of existing firm wholesale customers, and a forecast of distribution and transmission losses". • Newer plan contains implicit reference to price elasticity, but no explicit information on what that elasticity value is was included in the plan ("the usage equation captures season differences within a year, responses to weather, and changes in usage patterns over time that result from life-style changes, price, and other factors") • Newer plan acknowledges that weather impacts load forecasts (earlier plan does not mention the word "weather"—or anything related to weather)	collected from KEMA, EPRI, and NRDC studies—and New Mexico population estimates for future came from the U.S. Census Bureau. No known source for weather information.

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
Seattle	2006	2012	• Load forecast is only reported by mix of three types of customers: commercial, residential, and industrial (earlier plan reported loads for nine sectors: residential, commercial, government, food, metal, stone, aerospace, ship building, and other manufacturing) • Load is expected to grow about 1.4% annually over planning period without new programmatic conservation efforts; programmatic conservation efforts will decrease annual load growth to 0.8% average (earlier plan reported low of 0.3%, medium of 1.2%, and high of 1.9%) • Newer plan does not report low, medium, or high scenarios—only with and without programmatic conservation impact	• The newer plan contains no information on how load forecasts were produced, but it did indicate that system load is forecasted annually (earlier plan indicated that correlations were made between historical load for each customer sector and "selected economic and demographic variables") • Noted that each IRP cycle since 2008 has led Seattle to increase and then decrease the assumed adoption of EV in the load forecast (2008 IRP=67aMW; 2010 IRP=107-170aMW; 2012 IRP=8-36 aMW) • Use Monte Carlo simulation based on normal distribution of yearly data from 1981-2011—within Aurora XMP platform—to evaluate range of possible loads (earlier plan noted that SCL analyzed distributions of peak load, but it was not clear how these were used at the time).	• Seattle City Light now uses IHS Global Insight, Inc. for national economic/demographic forecast data and the Puget Sound Regional Forecaster for regional forecasts (earlier data source for economic and demographic forecasts was Dick Conway and Associates)

			Methodological changes since older IRP		
LSE	**Older IRP year**	**Recent IRP year**	**Framework**	**Variables and analytical techniques**	**Data sources (population, economic activity, weather, other)**
			• "Extreme weather conditions, very high or low temperatures, significantly affect the expected pattern of the usage of the electricity of City Light's customers when monthly studies are done, but it is not as significant as economic upturns or downturns when a yearly study is performed."		

15. Appendix D – Description of load sensitivity analysis in older and recent IRPs.

Colorado Public Service Company/Xcel Energy (COPSC)

COPSC's older plan includes both low and high forecasts due to a regulatory requirement imposed on the utility. These alternative forecasts are created by using first and third quartiles, instead of medians, for the underlying economic and weather variables that govern load growth. We could not find information indicating that the low (high) forecasts were used in the selection of the preferred portfolio.

However, in the more recent IRP, COPSC documented a more refined approach to include alternative load forecasts in the selection of the preferred portfolio. High and low sales estimates correspond to the 15% and 85% percentiles of an historic sales distribution. COPSC conducted sensitivity analyses by producing new portfolios for each high/low load forecasts, acknowledging that different load conditions require estimating alternative capacities—and combinations of technologies—necessary to meet load and policy mandates. In this example, the lower load forecast caused the capacity expansion model to suggest a portfolio that avoided building 0.7-1 GW of new NGCTs and NGCCs. Conversely, the higher forecast required an additional 0.9 -1 GW of the preceding technology types. It is important to note that these load-driven swings in capacity represent a significant portion of the total expected capacity (approximately 50%-75%) for this utility over the planning horizon. However, we found no evidence of an acquisition strategy that explicitly takes into account the potential for unplanned deviations in customer load.

Northwestern Energy (NW)

Regulations put forth by the Montana Public Service Commission require risk evaluation, management, and mitigation for both price and load (quantity) uncertainty (Mont. Admin. R. 38.5.8213 (1)(f)). According to these regulations, load uncertainty comes from variation in several underlying variables including fuel prices, environmental regulations, and weather—among other factors. Consequently, NW's older plan includes both high and low load forecasts. The utility expects lower load if market prices are lower than default supply prices. This leads larger customers to switch from the default rate to a retail rate and therefore reduces the load that the LSE has to procure for. Higher load forecast comes from the opposite effect. NW performs a qualitative sensitivity analysis by discussing the management and mitigation strategies under different risks. NW's qualitative sensitivity analysis is focused on short-term, operational cost risk rather than the potential for over or under-investment in infrastructure (capital risk). We find no direct connection between the alternative load forecasts and the qualitative discussion of management and mitigation strategies.

In a more recent IRP, however, NW develops and applies a stochastic risk assessment framework that employs statistical likelihoods (probability distributions) of future: fuel and electricity prices; CO_2 abatement costs; temperature; and monthly/seasonal/hourly loads. The NW stochastic-based model repeatedly draws from each probability distribution to evaluate the expected value and variance of short-term, operational costs under three portfolios. However, there appears to be no direct connection between longer-term load variation and investment levels in resource capacity, as capital investment levels for each portfolio are treated as a sunk cost. One justification for this approach may be that NW intends to rely on market transactions to balance its hourly and monthly positions. A large volume of market purchases would have to take place under higher-than-expected load, while a lower-than-expected load outcome could lead to the company selling their surplus capacity into the open market (NW, 2013, fig. 6-39).

Sierra Pacific Power (Sierra Pacific)

Sierra Pacific produced low and high load forecasts in their older IRP as required by Nevada regulation (Nev. Admin. Code § 704.9475). The low load forecast assumes a weaker-than-expected economy and exit of two large customers. Alternatively, the high forecast assumes a stronger economy and no loss of customers. The alternative load forecasts imply a ± 500 MW capacity position difference—or a ~40-50% of the 1GW of capacity planned by the final year of the planning horizon under the base forecast. Sierra Pacific identified 12 candidate portfolios with different installation years and plant capacity values to meet their base case load need. Low and high load forecast sensitivities resulted in contracted and expanded portfolios, respectively. The capacity contracted (expanded) in these alternative portfolios is consistent with the ± 500 MW position difference from the alternative load scenarios.

Sierra followed a very similar approach in a more recent IRP. Low and high load forecasts are built by modifying economic, mining activity, and DSM/DR/Net Metering penetration assumptions. As was the case earlier, sensitivity results for low and high load forecast conditions result in contracting or expanding the capacity of each portfolio and/or delaying or advancing potential procurement decisions, respectively.

Portland General Electric (PGE)

PGE produces high and low load forecasts that correspond to the base forecast growth plus and minus one standard deviation from the base, respectively. PGE explicitly acknowledges that these alternative forecasts do not reflect modeling of underlying economic and demographic variables, but simply intend to produce “demand boundaries, or jaws, that are sufficiently large to incorporate a mid-term departure from the reference forecast caused by business cycle and/or macroeconomic fluctuations.” (PGE, 2007, p. 41). Load growth sensitivity analysis is required as part of Oregon IRP regulations (Guideline 4b of Order No. 07-002) and includes high/low growth scenarios and stochastic load risk analysis. Weather is the only stochastically-determined variable affecting load in the PGE planning documentation.

PGE creates twelve portfolios designed to meet peak demand five years ahead of the IRP base year (in this case, 2012). PGE uses this approach to minimize the negative effect of long-term uncertainty in the selection of the preferred portfolio. In all portfolios, a third of the capacity required is met through short- and medium-term market purchases. The deterministic impact of alternative load growth forecasts in PGE's portfolios is then reflected in reduced or increased market purchases. This methodology assumes that market purchases are always on the margin and, as with other cases, ties the load growth forecast error to the electricity market price forecast error. PGE's more recent IRP follows the same load growth sensitivity approach used in the 2007 IRP.

Puget Sound Energy (PSE)

In the 2005 IRP, Puget Sound Energy adopted a scenario-based approach for the uncertainty analysis. PSE created internally consistent low and high economic performance scenarios with corresponding impacts to load growth and natural gas prices. For example, the average annual load growth in the base case was 1.8% with low and high scenarios of 1.2% and 2.3%, respectively. PSE analyzed four supply-side portfolios as part of their resource planning process. These four supply-side portfolios are quite similar and include coal, CCCT, and renewable energy options.

Puget Sound load growth sensitivity results show changes in the quantity of planned resources, but not significant changes in the type of supply-side resource or timing. It should be note that, while capacity differences are on the order of 5% of overall capacity, the corresponding monetary value of these portfolios under the base case, low, and high load forecasts differs by 15%-20%.

In a more recent IRP, Puget Sound follows the same methodology to define load forecast scenarios. In this case, however, PSE considers a broader set of variables that define a given scenario, including emission regulations for four pollutants, alternative fuel prices, various regional transmission constraints as well as both local and regional demand scenarios. We find that the difference between the low and high load forecasts scenarios is significant and ranges from 30%-50%. Interestingly, PSE implemented a stochastic modeling approach to develop candidate portfolios finding that these portfolios generally do not differ much across the load forecast scenarios.

Avista

Avista uses a dual-risk assessment approach that involves stochastic and scenario-based simulations, which are referred to as "futures" and "scenarios" in their IRP language. Avista prepared high and low forecast scenarios with the guidance of a Technical Advisory Committee. They use population growth in their service area as the sole driver for higher and lower load growth. They emphasize that these scenarios do not represent boundary conditions for load growth. In addition, they employ a distribution of hourly loads by month and week in each one

of 15 load zones in order to run a Monte Carlo analysis for Western Interconnect electricity prices. These distributions of load are mainly intended to represent short-term variation in load due to weather variation. Avista also develops and applies a stochastic analysis for natural gas prices, hydropower generation, and wind generation.

As is the case for other LSEs, Avista's stochastic analysis results do not isolate the specific effect of load growth uncertainty, because the simulation compounds all four sources of risk mentioned above. In addition, the load growth scenario analysis is limited to a qualitative assessment. Avista concludes that the frequency of the IRP process is short enough that load forecasts can be adjusted accordingly. Avista believes that "a shift in load growth will not substantially change the mix of resource types, but potentially could change the quantity." (Avista, 2005, p. 6.30)

In a more recent IRP, Avista develops its high/low forecast scenarios based on relating changes in load growth to changes in both customer number as well as electricity use per customer (UPC). Avista uses regional employment growth forecasts as drivers of the number of customers, while keeping UPC growth rates constant. In contrast to the earlier IRP, Avista conducted a quantitative-based scenario analysis. This technique involves identifying specific portfolios that meet low and high load conditions, adjusting for energy efficiency potential, and verifying that the risk profile of these new portfolios is similar to their original preferred portfolio. Through this analysis, Avista shows that timing of investments and the resource types are generally stable, but the planned capacities may increase (decrease) depending on load growth.

Idaho

The 2006 Idaho Power IRP introduces three long-term load forecasts (10^{th}, 50^{th}, and 90^{th} percentiles) and two additional short-term weather sensitivities (70^{th} and 90^{th} percentiles) based on the median value of the long-term forecast. Idaho Power then compares the performance of the preferred portfolio under two possible alternative load growth scenarios. They find that the preferred portfolio capacity would differ by ±400 MW (peak demand) under alternative scenarios, or roughly 25% of the total expansion over the 20-year analysis timeframe. Their planning strategy involves "utilizing a diverse mix of smaller, short lead-time resources… …[incorporating] the flexibility to adjust resource timing in the shorter term by either accelerating or deferring actual in-service dates to more closely match actual load growth." (Idaho, 2006, p. 85). They plan to adjust the timing and size of resource RFP for the preferred portfolio as a hedging strategy.

Idaho has continued to maintain its methodology to create short and long-term load growth scenarios, but has made recent innovations in their evaluation of the impact of these scenarios. For example, the 2013 IRP employs a stochastic approach (similar to Avista) and assesses the risk profile of their preferred portfolio against load growth and other variables with uncertainty. In addition, Idaho Power evaluates capacity margins given higher-than-expected load together

with lower-than-expected hydropower concluding that hydropower offers enough hedging against a wide range of peak demand forecasts.

LADWP

LADWP's older and newer IRPs employed the same methodology to develop alternative load forecasts. LADWP estimated two alternative peak demand forecasts: a one-in-ten chance of higher temperature (and higher demand) and a one-in-forty chance of lower temperature (and lower demand). These alternative forecasts are based on short-term weather stochasticity. LADWP does not consider long-term variability in load growth. LADWP indicated that weather variability does not affect annual energy consumption. For this reason, they did not develop an alternative energy sales forecast. LADWP indicated that a load sensitivity simulation was performed, but little or no information was provided on the method used or the results from this sensitivity analysis.

Seattle City Light

Seattle City Light's older IRP developed and applied alternative forecasts for energy sales, but not peak demand. These forecasts are based on four future scenarios that include fuel price, market structure, and environmental trends. Seattle City Light employs a stochastic analysis (i.e., Monte Carlo simulation) to repeatedly draw from probability distributions for each relevant variable and then input these values into a production cost model to quantify the range of costs for several different portfolios. It is not possible for external reviewers to assess the stand-alone impact of changes in load growth, but this method does consider costs under various load scenarios.

In a more recent IRP, Seattle City Light does not estimate high and low forecasts. Instead, they create a probability distribution from a sample of ~30 years of actual peak demand and repeatedly draw from this distribution to produce alternative load values for the production cost model described earlier.

PNM

In the earlier plan, PNM produced alternative load forecasts by increasing and decreasing their base forecast growth by ±1.5%. PNM found that there were only minor impacts to their preferred portfolio under these alternative forecast conditions. In addition, PNM conducted a probabilistic analysis to test the performance of their preferred portfolio by assuming a range of alternative values for three important inputs that are statistically correlated with one other (fuel prices, electricity prices and load growth). PNM reported that the preferred portfolio continued to be least-cost, low-risk but did not release additional information about how the details of the portfolio (e.g., timing of resource acquisition) might change under these different conditions.

In a more recent IRP, PNM uses a bottom-up approach to develop alternate load growth forecasts underpinned by economic growth, building code changes, and own and cross price elasticities. PNM then performed a detailed load sensitivity analysis that identifies the timing and capacity changes of portfolios for alternative low and high forecasts. However, PNM did not develop or implement a resource acquisition strategy to specifically address these changes.

Pacificorp

In their earlier IRP, Pacificorp did not produce alternate high and low load growth forecasts. Instead, Pacificorp employed a risk assessment methodology that estimated the impact of varying loads both in the short-term (due to weather) and long-term (due to economic conditions and technological change). Pacificorp used historical sales data to determine a distribution of probable future energy sales growth. For this reason, it is impossible to isolate the effect of load on the choice of portfolio. Pacificorp did not reformulate the timing or capacities in each of its portfolios, but determines a risk and cost profile for each fixed portfolio. This finding suggests that there was no specific strategy developed by Pacificorp to respond to the potential for higher or lower levels of load growth than expected.

In a more recent IRP, Pacificorp did develop and apply three load growth forecast scenarios for coincident system peak demand and energy sales. In this plan, Pacificorp identified alternative portfolios whose timing and size reflect the two alternate load scenarios and also assesses the monetary impact of several variables—including alternative load growth. Pacificorp indicated that load growth is the most important variable affecting the future revenue requirement. Pacificorp developed strategies to address these potential outcomes through a process called the “resource acquisition path”.

NV Power

NV Power does not report information describing any type of load growth sensitivity analysis in either the 2006 or 2012 IRPs.

16. Appendix E – Nameplate capacity expansion and load growth comparison

We compile incremental capacity expansion planning data from the older IRPs for the LSEs in our sample. Information about capacity expansion is usually reflected in the loads and resources tables corresponding to a utility IRP "preferred portfolio." The source for this and other information on long-term planning assumptions is the LBNL Resource Planning Portal (RPP[22]), an online system documenting nearly one hundred IRPs and supplemental surveys dating back to 2003.

We estimate total procured capacity additions by type of resource for each LSE starting from the same first year as indicated in the corresponding resource plan (see Table 1) through 2014—the last year for which procurement data are available. We include both owned capacity and contracts, which are the main supply side resources LSEs consider when developing their plans. We were able to attribute actual power purchase agreements (PPAs) by identifying the buyer—each one of the 12 utilities considered in this analysis—in a database of PPAs signed over the past 15 years (ABB-Ventyx, 2016).

In aggregate, the LSEs planned for ~ 20 GW of new nameplate capacity by 2015 in the IRPs reviewed in this study; roughly the same new capacity was actually realized (Figure 10). We find that actual self-builds new capacity levels were very consistent with planned self-builds capacity levels, with both reaching ~12 GW at the end of the analysis period. Realized PPAs were slightly higher than planned and grew faster than self-builds following the 2008/2009 crisis.

We compare the actual capacity growth rate to the actual peak demand growth rate and find that the actual capacity expansion of ~20 GW was almost five times higher than peak demand growth of ~4.5 GW during the same period (Figure 10, blue line). If we narrow the analysis period to 2007-2014, we find that the peak demand increased by less than 1 GW, but that there was nearly 8 GW of self-built capacity and about 7 GW of power purchase agreements signed over that period. As a benchmark, the planned incremental expansion of ~ 20 GW is only twice as high compared to the incremental forecast peak demand for the same period[23] of ~10 GW. The actual procurement to peak demand ratio was 15:1, whereas the planned resources to peak demand ratio was 2:1.

[22] See http://resourceplanning.lbl.gov

[23] In order to make a comparison over the entire time horizon, it was necessary to estimate some of the 2004-2007 values for certain plans depending on assumptions from the first year of analysis. We extrapolated using a linear regression to recreate those values – essentially using the same expected growth rates – to add the missing value for 2004-2007 for the LSEs whose plan year is 2005 or after (see Table 1 for the list of years for the older plans)

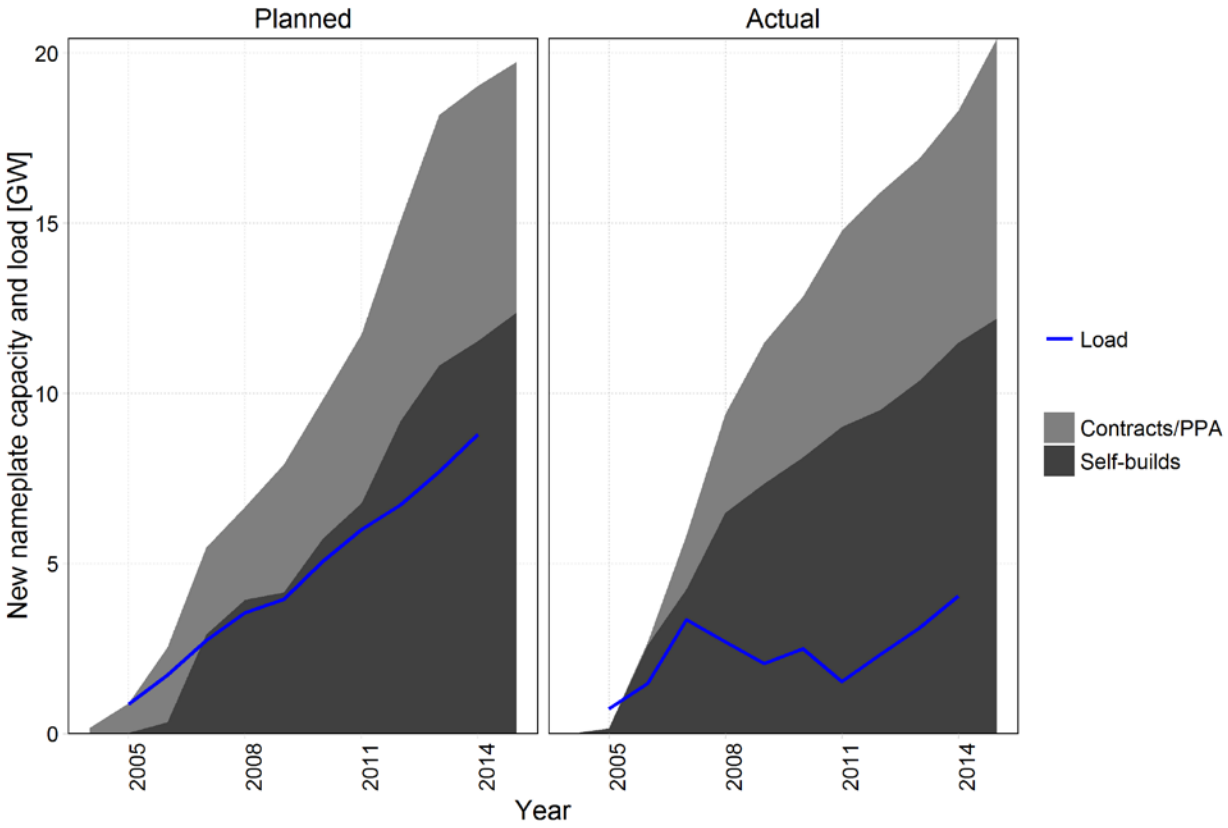


Figure 10 **Planned and actual nameplate capacity with forecasted and observed peak demand.**

EXHIBIT 110



Data Center Workgroup: Preliminary Report

December 1, 2025

Pursuant to Executive Order 25-05

Data Center Workgroup: Preliminary Report

Table of Contents

Introduction **3**
From the Governor's Office 3
Executive Summary 4
About the Workgroup 5
Workgroup Members 6
Findings **9**
Energy & Resource Impacts Subgroup Findings Adopted by Workgroup 9
Tax Revenue & Economic Development Subgroup Findings Adopted by Workgroup 14
Recommendations **22**
Appendix A: Minority & Concurrence Reports **25**
Appendix B: Other Feedback **62**
Appendix C: Rosters of Subgroups **66**
Appendix D: Report from Yakama Nation **70**
Appendix E: Executive Order 25-05 ..... **109**

Introduction

From the Governor's Office

This preliminary report reflects the outcomes of Governor Ferguson's Data Center Workgroup. The Governor's Office has directed the Department of Revenue to engage in consultation with the Tribes on the impacts of data centers. The final report will be published once consultation is complete.

We want to begin by thanking workgroup members and the public for their dedication of time, resources, and expertise to this process. The expansion of data centers in our state presents both significant opportunities and real challenges. We face an unprecedented amount of electricity load growth due to clean vehicle adoption, building decarbonization, population growth, and the retirement of fossil fuels. This challenge is compounded by data center growth. The workgroup took place amidst a surging public dialogue nationwide of how to limit, manage, or encourage technological development. Our state must consider how we move forward in a way that, at its core, improves the lives of Washingtonians.

This preliminary report is the culmination of six months of meetings and discussion, paired with over 1,000 public comments. Workgroup members spent countless hours throughout the year studying, debating, and refining these issues. While there were robust discussions and disagreements about the best path forward, the workgroup ultimately advanced a substantial set of recommendations by majority vote. Many workgroup members provided minority reports for findings or recommendations they had concerns or additional input on. The recommendations aim to ensure that data center growth aligns with Washington's climate laws, protects ratepayers, supports responsible energy growth, and safeguards natural and cultural resources.

Thank you for your interest in this important work. We hope you find this preliminary report useful, and we will send out the final report once the Tribal consultation process concludes.

Sincerely,

Beau Perschbacher
Senior Policy Advisor to the Governor
Economic Development & General Government

Kate Brouns
Policy Advisor to the Governor
Climate & Energy

Executive Summary

On February 3, 2025, Washington Governor Bob Ferguson issued Executive Order 25-05 which commissioned the creation of a Data Center Workgroup (Workgroup) to create a series of findings and policy recommendations as it relates to certain impacts of data centers and deliver them to the Governor no later than December 1, 2025. After the Governor's Office designated 33 Workgroup members, the Workgroup held its first meeting on May 9, 2025.

The Workgroup found that data center development in Washington is driven primarily by access to clean, reliable, and affordable energy; favorable tax incentives; efficient permitting; competitive ownership costs; and speed to market. These facilities have produced substantial economic and fiscal benefits—most notably in Eastern Washington communities like Quincy and East Wenatchee—by dramatically increasing local property values, lowering levy rates, funding public infrastructure, and creating jobs.

Washington offers limited sales and use tax exemptions for data centers, but no property tax incentives, unlike many other states that use robust, long-standing data center incentives to attract investment. Nationally, 37 states now provide some form of data center tax benefit, with Virginia and Georgia demonstrating particularly high returns on such incentives. The industry contributes significantly to Washington's economy, yet it faces challenges from rising energy demand, transmission and permitting constraints, and uncertainty around power availability and federal trade policies. While Washington currently has sufficient skilled labor available for data center construction, the state is falling behind in expanding the clean energy infrastructure needed to meet both growing electricity demands and its 100% clean energy goals.

The Workgroup also found that data centers may pose potential environmental and community impacts, particularly regarding energy use and related dam operations, water consumption, and localized ecological effects—which may also affect Tribal rights, interests, and resources. This underscores the need for coordinated planning, regulatory efficiency, early engagement with affected Tribes, and sustainable growth strategies.

The Workgroup's recommendations focus on ensuring Washington balances data center growth with climate, community, and energy system goals. They call for upholding the state's clean energy laws, protecting ratepayers by ensuring data centers cover their full energy system costs, and promoting energy efficiency and load flexibility through incentives and sustainability reporting. While protecting

community, Tribal, and environmental resources, the state should improve forecasting and transparency for new large energy loads and create a dedicated state entity to support the expansion of transmission capacity.

Washington should also streamline permitting for clean energy projects and accelerate deployment of emerging clean energy technologies—such as geothermal, long-duration storage, and nuclear—while enabling data centers to access or invest directly in firm, clean power. The Workgroup also recommends the Governor direct agencies to engage early with potentially affected Tribes about impacts to Tribal rights and resources and the potential for mitigation.

This report contains both the minority views and concurring opinions of Workgroup Members to both the findings and recommendations. It also contains some discussion of a proposed recommendation on data center tax preferences that failed to pass. The Yakama Nation is a Sovereign Government that agreed to participate as a member of the Workgroup. Given the unique government-to-government relationship between the State of Washington and the Yakama Nation, they were invited to provide their own perspective separately. We have included their report in Appendix D.

About the Workgroup

On February 3, 2025, Governor Bob Ferguson issued Executive Order 25-05 (see Appendix E) commissioning the creation of a Data Center Workgroup (Workgroup).

The Workgroup was directed to discuss certain impacts of data centers and generate findings on our state's economy, tax revenue, energy use, tribal resources, and the environment. It is further directed to consider possible policy recommendations that ". . . balance industry growth, tax revenue needs, energy constraints, and sustainability."

To fulfill the Workgroup's directive, two subgroups were commissioned: Tax Revenue & Economic Development and Energy & Resource Impacts subgroups. Workgroup members self-selected to serve on either or both. Of the Workgroup's 33 members, 18 self-selected to serve on both subgroups.

The subgroups were structured to create draft findings and recommendations for the full Workgroup's consideration, and the subgroups' draft recommendations were released directly for public comment.

Over the course of approximately 5 months, the Workgroup and its subgroups:

- Discussed the impacts of data centers as required in the Executive Order,
- Brainstormed possible policy recommendations,
- Sought and considered public feedback, and
- Adopted 31 findings and made 8 recommendations for consideration.

The Workgroup's individual members provided substantive contributions. For example, for the 18 who served on both subgroups, they invested approximately 40 hours in 23 meetings over the course of 5 months in meetings alone. Many were also asked to present on technical and complex topics.

Workgroup Members

Executive Order 25-05 directs the Department of Revenue to lead the Workgroup with representatives designated by the Governor's Office from the following:

- Department of Commerce,
- Utilities and Transportation Commission,
- Department of Ecology,
- Electric utilities,
- Environmental advocacy groups,
- Labor organizations,
- Industry stakeholders, and
- Others as designated by the Governor's Office

The following representatives served on the Workgroup:

State Government

- Kate Brouns, Climate & Energy Policy Advisor, Office of the Governor
- Beau Perschbacher, Economic Development & General Government Senior Policy Advisor, Office of the Governor
- David Duvall, Senior Tax Policy Coordinator, Department of Revenue (Data Center Workgroup Chair & Tax Revenue & Economic Development Subgroup Chair)
- Glenn Blackmon, Energy Policy Director, Department of Commerce (Energy & Resource Impacts Subgroup Chair)
- Andreas Bohman, Vice President for Information Technology and Chief Information Officer, University of Washington

- Diane Butorac, Clean Energy Coordination Section Manager, Department of Ecology
- Bill Kehoe, Director & Washington State Chief Information Officer, Washington Technology Solutions
- Brian Rybarik, Chair, Utilities and Transportation Commission
- Keith Swenson, Deputy Assistant Director, Office of Economic Development & Competitiveness, Department of Commerce[1]

Legislators (Non-voting members)

- Representative April Berg, 44th Legislative District
- Senator Matt Boehnke, 8th Legislative District
- Senator Sharon Shewmake, 42nd Legislative District
- Representative Alex Ybarra, 13th Legislative District

Other Workgroup Members

- Justin Allegro, Policy Director, The Nature Conservancy
- Zach Baker, Regional and State Policy Director, NW Energy Coalition
- Ryan Beebout, Vice President, Sabey Data Centers – West
- Cassie Bordelon, Executive Director, Climate Jobs Washington
- Dan Diorio, Senior Director, State Policy, Data Center Coalition
- Mendy Droke, Director, State and Regional Affairs, Pacific Northwest National Laboratory
- Matt Hepner, IBEW Executive Director of the Certified Electrical Workers of Washington, City of East Wenatchee Councilmember
- Latisha Hill, Vice President of Community Affairs & Chief Customer Officer, Avista Corporation
- Kirk Hudson, General Manager, Chelan County PUD
- Josh Jacobs, Clean Energy Strategy & Planning Vice President, Puget Sound Energy
- Heather Kurtenbach, Executive Secretary, Washington State Building and Construction Trades Council
- Casey MacLean, Washington Policy Manager, Renewable Northwest
- Michael Mattmiller, Senior Director of Government Affairs, Microsoft[2]
- Brant Mayo, Executive Director, Grant County Economic Development Council
- Megan Schrader, Director of State and Local Public Policy, Amazon Web Services
- Edward Sheets, Senior Advisor & Consultant on Regional Energy (Alternate for Yakama Nation)
- Cameron Steinback, Climate Justice Program Manager, Front and Centered
- Kate Valdez, Environmental Coordinator, Yakama Nation Fisheries

- Andy Wendell, Senior Power Manager of Large Power Solutions, Grant County PUD
- Seth Worley, Director of Government Affairs, UA Local 598

Findings

The findings that appear below were all adopted by the full Workgroup. They are divided into two sections: Those that originated from the Energy & Resource Impacts Subgroup, and those that originated from the Tax Revenue & Economic Development Subgroup.

Energy & Resource Impacts Subgroup Findings Adopted by Workgroup

1. **Washington policies regulate greenhouse gas emissions from the power sector and require a carbon-neutral electricity supply by 2030 and 100% renewable or zero-carbon by 2045. Achievement of Washington's climate and clean energy policy goals will require an abundant, reliable, and affordable clean energy supply.**
    a. Washington's cap-and-invest law sets a declining cap on greenhouse gas emissions that aligns with the state's greenhouse gas emissions limits.[3] The CCA covers emissions from in-state electric power, regardless of power plant ownership, and emissions from electricity imported into Washington.
    b. The CCA recognizes retail electric utilities are required to gradually transition to 100% clean electricity by 2045 and mitigates ratepayer effects of the CCA by providing no-cost allowances to them. No-cost allowances are based on forecasted resources of Washington utilities, including utility forecasts of data center loads.[4]

2. **Overall economywide demand in Washington for new, clean electricity sources is expected to increase for multiple reasons even without large new loads, including replacement of retiring fossil-fired plants and electrification of existing transportation, building, and industrial uses.**

3. **Multiple factors constrain the ability of the power system to increase capacity on pace with demand growth; these factors include land acquisition, siting and permitting timelines, long lead times on critical materials and equipment, extended delays in processing interconnection requests, transmission constraints, and impacts of state and federal policies and regulations.**

4. **The limitations of the Pacific Northwest transmission system are a significant constraint in accessing additional sources of clean electricity.**
    a. These limitations exist at multiple points in the grid, from long-haul capacity to reach resources across the West to local capacity to interconnect large new loads.

Reconductoring and grid-enhancing technologies represent a short-term, partial solution to adding capacity to the transmission system.[5]

5. **Because the power system is already constrained, any substantial new uses of electricity, regardless of purpose, challenge the state's efforts to decarbonize its energy system, maintain affordable and reliable service, and protect its environmental and cultural resources.**

6. **The global electricity requirements of data centers are substantial and growing rapidly in response to businesses and consumers demanding more data services. Data centers are the largest source of expected load growth in the Pacific Northwest. Potential growth in data centers in Washington would require significant electric power grid expansion, including generating resources, substations, and local and regional transmission capacity.[6]**
    a. Regionally, the Northwest Power and Conservation Council has projected that data centers and chip fabrication could add 2,200 average megawatts of electricity load by 2030. The power council's high growth scenario shows these loads increasing to about 4,800 average megawatts by 2030 and 6,500 by 2046.[7]
    b. Data centers may add significantly to peak loads.[8]
    c. The consolidation of data processing in large data centers has improved power use efficiency. New processes within data centers increase the density and total quantity of data center electricity loads.[9]

7. **The addition of large data center loads to the operations of retail utilities presents risks for other retail customers.**
    a. Future energy requirements of data centers are uncertain and difficult to forecast with accuracy.[10]
    b. Potential impacts to other customers arise as new investments and operating costs are recovered through rates. Data center electric consumption may adversely affect costs and reliability problems through wholesale power purchases, especially during peak periods.[11] Stranded assets could result if large customers exit before full recovery of investments made to serve those customers.[12]

8. **There are existing tools available to regulators and governing boards to manage potential impacts on other retail customers; however, working group members disagree over whether**

these tools are sufficient. The data center industry says it is committed to paying the full cost of service.

a. Examples of additional statutory and regulatory measures include limiting the obligation to serve, creating separate customer classes for data centers or large loads, data center or large load specific cost of service and rate design measures, such as application and service extension charges, contract term requirements, commercial credit commitments, resource planning requirements, and operating standards.[13]
b. Other state legislatures and regulators have proposed and adopted the additional statutory measures noted above to mitigate potential rate impacts of data centers for other retail customers.[14]

9. **Effective load forecasting is a foundational requirement for ensuring long-term grid reliability, resource adequacy, cost-effective transmission development. Additionally, utilities must be able to evaluate load requests for the purposes of identifying potentially speculative load requests. When forecasts are too high, they can lead to inflated capacity prices, trigger unnecessary transmission buildouts, and result in stranded or underutilized assets. When forecasts are too low, the consequences are even more severe: insufficient capacity procurement, underinvestment in transmission, and a persistent cycle of short-term emergency responses rather than long-term strategic planning.**

10. **To support accurate load forecasting, utilities must also be able to verify large load interconnection requests. At the same time, utilities must provide transparency on forecasting inputs and assumptions. Finally, potential large load developers require information from utilities about powering timelines without having to submit an interconnection request.**

11. **Opportunities exist to manage the power resource requirements of data centers, but workgroup members disagree about the viability of some of these opportunities and how to implement them.**

12. **Washington state tax incentives for data centers require data centers meet certain green building standards. These standards do not address the efficiency measures to cool the processors and are not sufficient to ensure that data centers achieve any specific level of energy efficiency or clean energy sourcing.**

13. **Data center operators and renewable energy project developers have collectively and globally procured and constructed many times more clean energy resources than the state's utilities.**
    a. The experience and expertise of these large corporate entities represent a potential resource for the state's utilities as they expand and decarbonize the grid. Large corporations that operate or principally use data centers may also have additional capital to invest in improving the grid (e.g., investing in grid-enhancing technologies).[15]
    b. Because of their broader resource portfolios, large tech companies may have more capacity to invest in emerging clean energy technologies than regulated or consumer-owned utilities.[16]
    c. Some data center developers and operators do not wish to manage electricity supplies, see benefits from being customers of electric utilities, and expect to pay the full and fair share of power system costs that result from their service.

14. **Generation and storage behind the meter, such as solar + storage and enhanced geothermal, could support data center energy demands that cannot be readily met with existing transmission capacity.**
    a. Addition of behind-the-meter or collocated generation and storage resources may require Federal Energy Regulatory Commission oversight, compliance with specific behind-the-meter interconnection requirements or navigating potential land or zoning restrictions. Land and zoning restrictions may prohibit generation and storage behind the meter.

[Please Note: Finding 15 was not adopted by the Workgroup.]

16. **Advanced nuclear technologies, such as small modular reactors, represent a potential source of clean, firm power, but members of the working group disagree on whether the technology is commercially viable in the near-term and whether advanced nuclear technologies can meet the forecasted power needs of data centers statewide. Permitting and siting challenges may further reduce and delay the development of this technology.**[17]

17. **Cooling systems and the use of fossil fuels to power data centers can affect air resources. Combustion generators release particulate matter pollutants and greenhouse gases. Cooling**

systems can release hydrofluorocarbons and other fluorinated gases. Water cooling systems can have other air emissions, such as anti-microbial emissions.

18. **Data centers may have potential direct and indirect impacts to tribal communities and treaty-protected resources, and the broader natural and built environment.**
    a. When multiple data centers are developed in the same geographic area, there can be cumulative impacts to resources such as air, water, transportation, and cultural resources.
    b. Developers can avoid and minimize environmental and other community impacts through coordinated planning and early engagement with state agencies, Tribes, and local communities when designing projects and choosing project sites.

19. **The direct water requirements of data centers can be substantial, depending on the size and type of cooling system used. This can affect water resources, such as water availability, and water quality through discharges of pollutants and effects on water temperatures. There could be potential impacts to public infrastructure, such as municipal water facilities, habitats, species, critical areas, and to Tribal rights, interests, and resources.**
    a. Impacts to water resources vary depending on a site's water availability, technology choices regarding cooling systems and water reuse systems, and other factors.
    b. Data centers that discharge water with pollutants or that include operations involving changes or discharges that affect waters can have potential impacts to waterbodies, habitats, and species and would require water quality discharge permits. Discharges to the Columbia River would have restrictions on temperature to ensure protection of salmon and habitat.
    c. There are also potential indirect impacts on water resources because of data center operations. To the extent data centers rely on hydropower for electricity supply, the additional electricity load of these facilities increases demand for this scarce resource, particularly during critical periods for the power system, and is likely contrary to the efforts of Tribes, the state, and others to achieve healthy and abundant fisheries.

20. **General permits and general orders can reduce project timelines and ensure state regulatory requirements are met. These measures allow a proposed project to use pre-evaluated conditions and criteria and take less time than an individual permit.**

a. Ecology has existing general permits for water discharges and is developing a general order for data center emergency engine operations.[18]

Tax Revenue & Economic Development Subgroup Findings Adopted by Workgroup*

Please note: There are gaps in the numbering of the findings below because some of the findings considered by the Tax Revenue & Economic Development Subgroup were not forwarded to the full Workgroup for consideration. This is true for all of the findings that do not appear below except T.7 and T.15. They were tabled by the Workgroup and were not considered further.

T.1 Key Factors in Siting Data Centers Generally

- The following were identified as key factors in a developer's decision to site a data center. Industry emphasized that not all factors have the same weight in decision-making:
  - Access to fiber/interconnection.
  - Access to water for industrial purposes.
  - Access to clean, reliable, and ample energy.
  - Climate and risk of natural disaster.
  - Land availability.
  - Tax incentives.
  - Regulatory climate (including permitting and permitting timelines).
  - Other cost considerations:
    - Ownership/occupancy costs
    - Land
    - Construction
    - Ongoing operations
    - Electricity
  - Time to market.
  - Access to skilled construction and technology workforce.
  - Tax and regulatory certainty.
  - Cooler climate (naturally reduces load); and
  - General risk management (e.g., civil unrest, cybersecurity).

T.2 Key Factors Receiving the Greatest Weight in Siting Data Centers in Washington

- From the factors listed above in Finding 1, the following were identified as key factors bearing the greatest weight in a developer's decision to site a data center in Washington:

* Please note that some of this Subgroup's draft findings were amended before the Full Workgroup.

- Access to clean, reliable, and affordable energy (Industry noted that without electricity, none of the other factors matter).
- Tax incentives.
- Regulatory climate (including permitting and permitting timelines);
- Time to market.
- Ownership/occupancy costs.

T.3 Tax & Economic Development Benefits from Data Centers in Certain Local Washington Communities

- Data Centers have and are making a positive tax and economic impact on certain Washington Communities.
  - For the purposes of state and local property taxes, the additional assessed value of data centers on the town of Quincy (approximately 8,500 people) enabled the city to reinvest and upgrade services while its citizens pay less in property taxes.
    - In 2006 *before* data centers located to Grant County, the assessed value of the top 10 taxpayers in Grant County was $312,977,310 which represented $4,246,801 in tax paid.
    - In 2025 *after* data centers located to Grant County, the assessed value of the top 10 taxpayers in Grant County was $6,136,727,665 (a 1961% increase over 2006) which represented $54,267,353 in tax paid (an increase of 1277% over 2006). 7 of the 10 highest assessed values and taxes paid are from data centers, and 6 of the 7 are located in Quincy. (The seventh is located in Moses Lake.)
    - The data center's additional assessed value has driven down the City of Quincy's levy rate over time. The current rate is approximately 70% less than it was in 2006 before data centers located to Quincy. As a result, Quincy's other taxpayers are generally paying significantly less in property taxes.
      - 2006 (before data centers): $3.12 per thousand
      - 2016: $1.97108 per thousand
      - 2025: $0.87788 per thousand
    - As a result of lower levy rates, the City of Quincy has been able to replace, upgrade, and/or newly construct important buildings and infrastructure in the city. In some cases, voter approval was secured to finance some of these projects such as a bond to build a new high school:
      - New reuse water system
      - New wastewater treatment plant
      - All wastewater systems replaced (e.g., piping, etc.)

        - While the City had sidewalks on approximately 5% of its streets, approximately 80% of the city's streets now have sidewalks. 95% of streets are now paved.
        - New schools (including a new High School).
        - New Quincy Valley Medical Center (hospital).
        - Quincy Public Market
        - New City Hall
        - New Fire Station (which resulted in lower fire insurance rates for businesses and individuals and the ability to lend assistance to the surrounding area outside of Quincy).
        - New City of Quincy Public Safety and Policy Department.
    - In the near future, Quincy will construct a Q Plex, a new indoor soccer facility, with four soccer fields and other amenities. Quincy anticipates this would bring hotels to the area and help with tourism.
    - Similar property tax benefits have also been found in at least one other data center cluster found in other Eastern Washington communities.
        - East Wenatchee has a cluster of data centers.
        - An analysis of one parcel in East Wenatchee (Douglas County) indicates that the additional value data centers there add to the tax rolls is having the effect of driving down property tax levy rates:
            - 2023: $9.82 per thousand
            - 2024: $8.41 per thousand
            - 2025: $7.82 per thousand
        - Two new data center campuses are in different stages of construction in East Wenatchee (Douglas County) and in Malaga (Chelan County). It is expected that this continued economic development will continue driving property tax levy rates significantly lower in these communities.
    - In Quincy alone data centers have created approximately 900 jobs *directly*:
    - In Washington, different organizations use different measures to describe the indirect impacts of data centers on jobs. The Tax Revenue & Economic Subgroup saw presentations where estimates ranged from 1 direct data center job helps create approximately 4 indirect jobs to 1 direct data center job helps create approximately 6 indirect and induced jobs.
- Centeris Data Center located in Puyallup is an urban, co-location multi-tenant data center has also made large investments in its data center which has benefitted the Puyallup area.
    - The Centeris data center was originally built to be a semiconductor manufacturing facility which was never occupied. The Benaroya Company purchased it in 2009 and converted it in 2010. As a result, the building received LEED Gold certification.

- Centeris credits the non-rural data center tax incentive passed in the 2022 Legislative Session (ESHB 1846) as the reason:
  - Its property went from vacant to 100% occupied.
  - 130 union electricians were hired to be on-site throughout the 21-month project contributing approximately 275,000 hours.
  - Members of other union trades were hired to provide an additional 121,000 labor man hours to work on mechanical systems, carpentry, fire suppression, etc.
- Centeris' owner, The Benaroya Company, invested $200 million into the facility since 2024, and its tenants have contributed millions into the local economy. Centeris has employees, contractors and vendors providing both direct and indirect positive economic impacts.
  - Centeris currently employs 21 full-time data center employees. All new employees receive compensation at least 125% above the per capita income of Pierce County, and Centeris contracts with third party vendors who use 50-100 employees to maintain its equipment.
  - Currently, Centeris employs 45 union personnel to keep its data center operating. In addition, Centeris employs other union personnel to provide additional support which averages about 20 employees per month.
  - Approximately 60% of Centeris' employees are military veterans.
  - Each of Centeris' tenants staff 5-10 full-time employees and the tenants engage the services of third parties to service the tenants' equipment.
- Centeris uses air for cooling and only uses water when the temperature exceeds a certain level. Even then, the water used is recycled and reused for cooling later. Centeris considers the level of water consumption *at this facility* as relatively low.
- Centeris has been recognized by several Pierce County-area organizations for improving the economic well-being of Pierce County and Washington State.

T.5 Data centers pay state and local taxes – Washington offers limited sales & use Tax Exemptions.

- Under current law, there are two sets of data center sales and use tax exemptions on *eligible server equipment* and *eligible power infrastructure* in a qualifying data center:
  1. For Rural Data Centers: RCW 82.08.986 and RCW 82.12.986, and
  2. For Non-Rural Data Centers: RCW 82.08.9861 and RCW 82.12.9861.
- Both exemptions are limited:
  - Eligible server equipment includes things like the original server equipment installed in a data center, replacements of those servers, etc.

- Eligible power infrastructure is limited to fixtures and equipment necessary for the management of electricity such as generators, wiring, cogeneration equipment, and other similar equipment.
- Charges for labor to install both eligible server equipment and eligible power infrastructure are also exempt under these incentives.
- All other labor, services, and materials are subject to state and local sales tax. For example, the shell of a building and a data center's HVAC system are generally subject to state and local sales tax.

- Data centers are subject to state and local property taxes. There is no current property tax-related tax incentive for data centers in Washington State. Other states however offer state and/or local property tax incentives (e.g., Oregon, Ohio, Georgia, Indiana, etc.).

T.6 Data Center Tax Incentives Not Available in All Counties

- Under current law, data centers constructed in the following counties and any tenants of those data centers are excluded from the data center sales and use tax incentives in RCW 82.08.986, RCW 82.12.986, RCW 82.08.9861 and RCW 82.12.9861:
  - Thurston
  - Kitsap
  - Whatcom
  - Clark
  - Benton
  - Spokane

T.8 Data Center Tax Landscape Across the United States

- The data center tax landscape across the United States is varied.
  - Sales tax exemptions for data centers have existed for decades in some states. These exemptions follow the same principles that have supported long-standing exemptions for other large capital intensive industries. 41 states currently exempt sales tax on manufacturing equipment.
    - Under RCW 82.08.02565 and RCW 82.12.02565, Washington provides a sales and use tax exemption for machinery and equipment used directly in a manufacturing operation – this exemption does not extend to buildings and certain other fixtures such as utility systems for heating, air conditioning, communications, plumbing, or electrical.
  - Sales tax exemptions for data centers have also been used as economic development tools in states offering these incentives and are deemed by data center developers as an important siting criterion.
  - Oregon does not have a sales tax but offers property tax incentives and abatements for investments in designated opportunity zones.

- States that have seen the most growth in data centers are typically those with robust incentives. California is an exception because of Silicon Valley and its technology industry.
- Currently 37 states offer data centers tax incentives. Several states have adopted or created new sales tax exemption programs for data centers (i.e., Arkansas, Florida, Kansas, Kentucky, Louisiana, Massachusetts, Michigan, Minnesota, Wisconsin, and West Virginia all adopted new or expanded programs since 2023), while at least two states have considered pausing their programs within the last two years (The Governors of Georgia and Ohio vetoed legislation to pause programs).
- As they have always done in developing their economic development toolkit, states calibrate their incentives to ensure their policy priorities are met. A sampling of requirements placed on incentives reflect this calibration, including:
  - A minimum investment,
  - Job and/or salary requirements,
  - Various reporting requirements,
  - Penalties or clawbacks with repayment of taxes,
  - Exemption of sales tax on purchases of electricity,
  - Sustainability/Green building certification.
  - Tailor policy to specific data center models (self-performing data centers versus multi-tenant data centers).
  - Empower a state agency (Ohio) with discretion so as to somewhat customize its incentives and the period of time that the exemption can last on a project-by-project basis.
  - Minnesota provides a tax rebate instead of an exemption which, according to industry, makes the exemption administratively burdensome to implement.
  - Tailoring the items eligible for exemption and overall terms to meet each state's respective priorities, such as limiting an exemption on power purchases but extending the overall term on equipment exemptions.
- Georgia is currently the fastest growing market. Virginia constitutes the largest data center market.
- Virginia has also created a Mega Data Center Incentive Program which includes a longer extension of existing sales and use tax exemptions for data center companies dependent on specific investment and job creation targets.
- Two audits have been done in Virginia and Georgia to examine the impacts of their tax incentives for data centers:
  - Both audits concluded that up to 90% of investment wouldn't have happened if not for each state's incentives provided to data centers.
- In Virginia's audit of its data center tax incentives, they further concluded:

- Overall, Virginia's data center incentives program provides more benefit than "the average Virginia incentive."
- Virginia's data center incentives create more jobs than its other incentives.
- Personal income was higher from data center jobs than jobs created by other Virginia tax incentives.
- Virginia's GDP was higher under data center incentives than under other incentives.
- Virginia's return in revenue per dollar forgone under its data center tax incentives was higher than that from other incentives.

T.9 Biggest Risks Data Centers Face

- Industry indicated that the biggest risks data centers face include the following:
  - Business uncertainty around tariffs (federal policy) as it makes it hard to make deals with customers because the true costs are unknown.
  - Also, existing supply chain constraints create uncertainty for time to market.
  - Uncertainty around power. Demand from businesses and consumers, including AI, continues to exceed existing data center capacity. As data centers develop and need power for operations to serve demand, lead times for power delivery and energization in jurisdictions are increasing.

T.12 No Labor Shortage in Washington to Meet Data Center Needs. Future Labor Profile Depends on Demand.

- There is no shortage of labor in Washington to meet data center's needs in terms of new construction, refurbishment, expansion, upgrades, and ongoing maintenance of previously constructed data centers.
  - With 75% of the unions affiliated with the State Building and Construction Trades reporting, as of the start of 2025, there are nearly 9,955 construction workers out of work.
  - Over 1,700 of the workers reported out of work are apprentices. New apprentices cannot be enrolled when there are so many already in the system who cannot finish their training because there are not enough job sites for them. Apprenticeship utilization requirements, project labor agreements, and community workforce agreements ensure these requirements are met.
  - According to IBEW's data, 1,000 electricians in Washington are currently working on data center-related projects (as of July 2025) and 300 apprentices are currently being trained. In addition to working on new data center construction projects, these electricians also help to maintain and upgrade electrical systems and components of previously constructed data centers.

- According to IBEW's data, Washington has 2,000 electricians on unemployment who are ready and waiting for work.
- IBEW Local 191 built an apprenticeship training center in East Wenatchee–the first on the east side of Washington. They are looking at building a second training center in Moses Lake.
- The demand for skilled labor (electricians and other skilled labor) from data center-related projects and training centers training up new workers explains the current labor numbers for electricians.
- According to the Washington State Building and Construction Trades Council, the pattern they see is a shift in work from Western Washington to Eastern Washington.

T.13 Washington is falling behind in building out the infrastructure – generation, transmission, and battery energy storage — necessary to achieving the state's clean energy goals.19

T.14 Annual Survey Data from Data Centers and Data Center Tenants Indicates Tax Savings to Data Centers and Tenants

- According to Department of Revenue's Annual Tax Preference Performance Report data, data centers and data center tenants reported taxpayer savings of approximately $584 million over the last decade (2012-2023). In 2023, the most recent data available, tax exemptions totaled over $118 million.

T.16 Data Center Industry's Aggregate Impact to Washington's Employment and Taxes in 2023.

- According to a 2025 report from PwC, commissioned by the Data Center Coalition, the data center industry contributed 8,990 direct jobs in Washington in 2023.
- Including direct, indirect, and induced effects, the data center industry's total employment contribution was 47,960 in Washington in 2023.
- According to a 2025 report from PwC, commissioned by the Data Center Coalition, the Washington data center industry directly and indirectly contributed $1.8 billion to state and local tax revenues in 2023. This is based on publicly available data and is net of any tax incentives.
- Additionally, PwC's analysis of the latest government spending data suggests that the data center industry's total state and local tax contribution of $1.9 billion in Washington in 2022 was sufficient to fund all provision and support of parks and recreational facilities and activities, as well as all administration costs of unemployment compensation, public employment offices, and related services in the state.

Recommendations

Workgroup members brainstormed ideas for possible recommendations in their individual subgroups. Each subgroup considered the ideas and voted to forward its slate of draft recommendations for public comment. After having received more than 1,000 comments, the Department shared the public comments with all members of the Workgroup for their consideration. Then certain draft recommendations and topics were selected and workshopped in several joint subgroup meetings. Based on those discussions and public comments, the Governor's Office compiled a list of draft recommendations for consideration by the full Workgroup. Please note: The Department of Revenue did not submit any recommendations as the Department typically defers to the Governor and Legislature on policy decisions.

The following recommendations were adopted by a majority vote of Workgroup members present:

1. **Maintain the integrity of Washington's climate laws.**
   - Ensure Washington's Climate Commitment Act and Clean Energy Transformation Act operate as envisioned to cover any fossil or unspecified power sources used by large data centers.

2. **Strengthen ratepayer protections.**
   - Require the UTC and consumer-owned utilities develop model tariffs or model contracts for a new rate class that: (1) identify a MW threshold for the tariff serving new large loads; (2) specify the characteristics of these new loads; (3) require new large loads pay for the direct interconnection costs caused by their interconnection; (4) require new large loads cover any costs of generation, transmission or distribution systems required to serve new large loads and avoid shifts of costs or risks to other customer classes, including potential stranded assets.

3. **Incentivize load flexibility and best practices for energy efficiency.**
   - Direct agencies to identify, incentivize, and unlock the potential for load flexibility, particularly from large data centers. Incentives could include specific tax incentives or faster interconnections for large loads that are able to participate in demand response programs or those that help fund demand response and energy efficiency for low-income households and other customers.
   - Require data centers to publish a sustainability report prior to construction that demonstrates how the data center balances energy, water, and computing performance. Require the report to be updated when replacing equipment.

- Fund the Energy Policy Office to conduct a study on the potential to meet data center loads with on-site energy generation or storage, demand response programs, or load management programs, and include recommendations on any program or policy changes that may be needed to achieve the potential.

4. **Protect community, Tribal, and environmental resources.**
   - Direct and fund the Department of Ecology to conduct a study and develop best practices for siting and operating data centers with input from permitting agencies, industry, Tribes, interested parties, local government, and utilities. The study will address:
     - Water resources, including water availability, water quality impacts, direct and cumulative impacts on the local water system, and potential for discharges that cause a municipal water system to exceed its capacity resulting in untreated water entering streams or rivers;
     - Impacts to Tribal rights and resources; and
     - Air resources, including greenhouse gas emissions and direct and cumulative air emissions.
   - Replace the data center sustainability provisions in existing law [such as RCW 82.08.986(4)] with a standard that more specifically encourages energy and water efficiency at newly constructed data centers.
   - Require data centers to report water use annually to the state. The report should include daily quantities (total and peak uses) and any effluents that are discharged outside the data center.
   - Encourage the Northwest Power and Conservation Council (NPCC) to incorporate the anadromous fish managers' recommendations on the spill and reservoir operations at the dams into the Columbia Basin Fish and Wildlife Program. The NPPC would then incorporate those operations into the development of the next Pacific Northwest Conservation and Electric Power Plan.

[Please Note: Recommendation 5 was not adopted by the Workgroup.]

6. **Improve resource forecasting.**
   - Direct the UTC and the Department of Commerce to create reporting standardization for new large loads across regulated and public utilities, which could include data quality, documentation, and information about associated transmission needs.
   - Establish standardized commercial readiness criteria across utilities for large load additions to enter the interconnection queue.

- Require large load applicants to disclose duplicative interconnection requests across balancing authorities.

7. **Enhance transmission capacity.**
   - Create a state entity to support the development of transmission projects, which could include permitting, land acquisition, finance and even construction.
   - Direct agencies to prioritize upgrades to existing transmission lines with grid enhancing technologies.

8. **Accelerate siting and permitting of transmission and clean energy generation.**
   - Direct agencies and local governments to accelerate processes for development of transmission and clean energy generation, in line with the recommendations of Washington's Interagency Clean Energy Siting Council and the work being undertaken via Executive Order 25-03.
   - Direct state and local agencies to engage early with potentially affected Tribes about impacts to Tribal rights and resources and potential for mitigation.

9. **Accelerate the deployment of existing and emerging technologies, such as geothermal energy, green fuels, long-duration batteries, and nuclear energy to provide data centers with firm energy.**
   - Create a direct access program for new large loads in Washington to allow customers to source their own power.
   - Design green tariffs for large data center companies to invest in innovative higher-cost clean energy resources, such as long-duration battery storage.

Appendix A: Minority & Concurrence Reports

November 7, 2025

David Duvall
Chair, Data Center Work Group
Senior Tax Policy Coordinator | Executive Division
Washington State Department of Revenue

Dear Chair Duvall:

The Data Center Coalition (DCC), as a member of the Data Center Work Group, appreciates the opportunity to offer this minority report. We would like to thank Governor Bob Ferguson, his staff, and agency staff for their hard work in organizing the work group and conducting a balanced and open conversation on a wide range of issues. We respectfully offer the following comments related to both findings and recommendations.

Energy & Resource Impacts Subgroup Finding #7: The addition of large data center loads to the operations of retail utilities presents risks for other retail customers.

DCC disputes the assertion that the addition of large data center loads presents risk to other utility customers. Utilities throughout the country have offered public statements that data center-driven load growth will generate significant new revenues for electric utilities, and those revenues can create downward pressure on the rates that all customers pay. PPL noted as such in its April testimony in the Pennsylvania Public Utility Commission (PUC) *En Banc* hearing.[1] Earlier this year, PG&E, a major investor-owned utility in California, estimated that the 10 GW of new data center load growth could benefit all ratepayers by spreading fixed grid costs across higher total energy consumption —potentially reducing average electricity costs by more than ten percent.[2] And, in recent videos, Georgia Power confirmed that data centers will not impact electric bills for Georgia residents and that the addition of data centers and large load customers enabled the utility to

[1] PPL Electric Utilities Corporation, "Testimony of Joseph B. Lookup, Vice President-Transmission & Distribution Planning and Asset Management," En Banc Hearing on Interconnection and Tariffs for Large Load Customers Docket No. M-2025-3054271, available at https://www.puc.pa.gov/pcdocs/1875751.pdf.

[2] Pacific Gas & Electric, "PG&E Data Center Demand Pipeline Swells to 10 Gigawatts with Potential to Unlock Billions in Benefits for California," Press Release, July 31, 2025 *available at* https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/PGE-Data-Center-Demand-Pipeline-Swells-to-10-Gigawatts-with-Potential-to-Unlock-Billions-in-Benefits-for-California/default.aspx?utm.

freeze customer rates for a three year period. New rules established by the Georgia Public Service Commission help ensure that data centers pay for the infrastructure to support their operations.[3]

Furthermore, a recent study from Lawrence Berkeley National Laboratory and the Brattle Group found that between 2019 and 2024, states with significant load growth saw average prices decline. The biggest factors behind rising prices were the costs of poles, wires, and other electrical equipment—as well as the cost of safeguarding that infrastructure against future natural disasters.[4]

Lastly, the data center industry is fully committed to paying its full cost of service for the electricity it uses. Traditional rate-making principles of cost causation and avoiding cross subsidization, as well as effective forecasting principles, can and should address concerns. While we recognize that management of the grid is ultimately the responsibility and duty of utilities, regulators and grid operators, the data center industry is committed to being an active and engaged stakeholder.

Energy & Resource Impacts Subgroup Finding #8: There are existing tools available to regulators and governing boards to manage potential impacts on other retail customers; however, working group members disagree over whether these tools are sufficient. The data center industry says it is committed to paying the full cost of service.

Sub-bullet (a) lists "limiting the obligation to serve" as an example of a measure available to manage potential impacts of data centers on other retail customers. DCC vehemently disagrees that this is a measure that should be considered. The obligation to serve is a fundamental principle that underpins the entire regulatory system for delivering electricity. Utilities are afforded an effective monopoly in exchange for delivering electricity services pursuant to requests inside utility services territories. Allowing utilities to deny service would create significant disparities and inequities within the Washington electricity grid and risks creating a dangerous precedent allowing utilities to deny service based on end use.

Importantly, data centers are aligned with the state's clean energy goals. Limiting the obligation to serve could also have the unintended effect of chilling overall data center investments/growth, which includes investments in clean energy resources and new technologies that both the state and data centers need to meet their respective clean energy goals.

Recommendation #3: Incentivize load flexibility and best practices for energy efficiency.

DCC would like to provide clarification and important information regarding data centers participating in demand response programs. Data centers provide essential services, supporting healthcare, banking, finance, and national security among other sectors. Data centers have contractual obligations to maintain 99.999% uptime. As such, data centers **cannot turn off**. Instead, the industry will utilize backup generators to maintain services if participating in demand

[3] Georgia Power, "Your Base Rate is Staying the Same until 2028" *available at* https://www.georgiapower.com/rate-freeze.html (last accessed Oct. 20, 2025).

[4] Lawrence Berkeley National Laboratory and the Brattle Group, "Factors Influencing Recent Trends in Retail Electricity Prices in the United States," October 2025, available at https://eta-publications.lbl.gov/sites/default/files/2025-10/full_summary_retail_price_trends_drivers.pdf.

response programs. This presents compliance challenges under existing air permits required under federal and state laws. In addition, zero emitting backup generating technology today does not have the operational capabilities to meet the 99.999% uptime requirements at data center scale.

Additionally, while we generally oppose a disparate requirement singling out one specific industry to publish a sustainability report, data center operations also are misunderstood in this recommendation. Specifically, data centers replace servers and computer equipment every three to five years on a rolling basis, which is highly dependent on supply chain lead times. Thus, there could be a scenario in which a data center would have to update a report multiple times a year, or even monthly or weekly. This presents a significant compliance burden and was likely not the intention of this recommendation.

Recommendation #4: Protect community, Tribal, and environmental resources.

Data centers reporting water use, including on such a granular basis, imposes a disparate legal requirement on one specific water user in Washington that offers no value to understanding overall water use in the state. Data centers are among the most efficient water users throughout the economy. In Virginia, the largest data center market globally, the Joint Legislative Audit and Review Commission found that 83% of data centers in the state use as much, if not less, water than a large commercial office building, and that data center water use across the state is sustainable.[5]

Without broad-based reporting across industries, Washington risks giving other water users less accountability and establishes a construct where data center water use cannot be compared to alternative commercial and industrial water uses, thus providing no probative value for policymakers or the public. Furthermore, data centers work closely with local water authorities on resource availability, routinely invest in water infrastructure in communities, and are deploying water efficient cooling systems. State leaders should not impose broad-based legal requirements based on anecdotal circumstances. The state should seek to establish a baseline, through independent evaluation, to make informed decisions regarding water use.

Recommendation #6: Improve resource forecasting.

Sub-bullet three recommends disclosing interconnection requests across balancing authorities in Washington. This specific recommendation is not needed if proper forecasting principles are adopted in accordance with other sub-bullets in this recommendation. In addition, it would expose data centers to competitive and proprietary risk, offer no confidentiality protection, and risk skewing forecasts with insufficient information. It is unclear how utilities would factor this information into evaluating load requests and whether it would actually improve forecasts relative to other recommended measures.

Much of the work group conversation on this item focused on Senate Bill 6 (SB6) in Texas as the model. Specifically, SB 6 states:

---

[5] Joint Legislative Audit and Review Commission (JLARC), "Data Centers in Virginia," page v and 45, December 2025, *available at* https://jlarc.virginia.gov/pdfs/reports/Rpt598-2.pdf.

> The standards must require each large load customer subject to Subsection (c) to disclose to the interconnecting electric utility or municipally owned utility whether the customer is pursuing a substantially similar request for electric service in this state the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection request.

This language provides specific detail and criteria for disclosing the request, which is critically important and which the sub-bullet does not detail.

SB 6 is currently being implemented with a significant rulemaking process. If SB 6 serves as the basis for this recommendation, then it should not be included until the rulemaking is completed and has time to be effective, so Washington can then evaluate its impact and effectiveness.

The data center industry will continue to be an engaged stakeholder in Washington

DCC believes that with thoughtful policy development and continued collaboration, Washington can maintain its position as a leader in the digital economy while ensuring responsible growth. The data center industry stands ready to work with state leadership to implement balanced solutions that protect ratepayers, support grid reliability, and foster economic development.

Data centers represent significant capital investment, high-paying jobs, and tax revenue that can benefit Washington communities for decades to come. We respectfully urge you to consider these perspectives as the state moves forward with data center policy, ensuring that Washington remains competitive in attracting the digital infrastructure investments that are essential to our modern economy.

Thank you again for the opportunity to participate in this work group. We look forward to our continued partnership in building a sustainable and prosperous future for Washington.

Sincerely,



Dan Diorio
Vice President, State Policy
Data Center Coalition

November 7, 2025

Minority Views, Governor Ferguson's Data Center Workgroup

As a participant of the Data Center Workgroup ("Workgroup"), Renewable Northwest ("RNW") submits the following minority views on the Workgroup's recommendations which are primarily suggestions for further clarification and strengthening of the recommendations. RNW is not submitting any minority views on the Workgroup's findings. RNW is a nonprofit organization that advocates for the rapid and responsible decarbonization of the electricity grid across Washington, Oregon, Idaho, and Montana. Our unique organization draws knowledge from our diverse membership, which includes clean energy developers, manufacturers, consulting firms, environmental and consumer advocates, and clean energy buyers including data center companies.

We appreciate the efforts made by the Governor's Office and Department of Revenue to produce factual, balanced findings and evidence-based recommendations, and these minority views are largely supplemental.

Recommendations

2. Strengthen ratepayer protections
RNW supported this recommendation. We would also support mandatory long-term contracts with minimum off-take provisions, in order to minimize stranded costs. We would also frame this as a recommendation for the UTC and consumer-owned utilities to *consider* establishment of a new rate class, rather than mandating they do so, to allow them flexibility to consider and respond to their unique situations.

3. Incentivize load flexibility and best practices for energy efficiency
RNW supported this recommendation. We would also add a 4th element to this recommendation: "Consider offering programs and/or incentives that allow for flexible grid assets–such as battery storage–to be co-located with a data center to increase the ability of data centers to shift load off-peak. Such programs and/or incentives should be tailored to match the commensurate benefit of shifting peak load."

6. Improve resource forecasting
RNW supported this recommendation. We suggest an important language clarification in the first bullet point:
"Direct the UTC and the Department of Commerce to create reporting standardization for *forecasting the impacts of* new large loads across regulated and public utilities, which could include data quality, documentation, and information about associated transmission needs."

7. Enhance transmission capacity
RNW supported this recommendation. We suggest an additional point to include in this recommendation: “Enable transmission planning that prioritizes least-regrets solutions and enhances capacity in the most needed areas of the grid.” We also recommend working in a direct reference to battery storage as a transmission asset and the importance of considering and deploying grid enhancing technologies for enhancing transmission capacity.

8. Accelerate siting and permitting of transmission and clean energy generation.
RNW supported this recommendation. We strongly urge adding a direct reference to battery storage as it is unique and complementary to clean energy generation and transmission. It can also support “bring your own generation” approaches for data centers and enhance general grid reliability.

Thank you to the Governor’s Office and Department of Revenue for your efforts over the course of 2025 to engage deeply in this critically important issue. RNW stands ready as a resource for any future engagement or questions around large loads and maximizing clean energy infrastructure.

Sincerely,

/s/
Casey MacLean
Washington Policy Manager
Renewable Northwest

TO	David Duvall, Kate Brouns, Beau Perschbacher, Glenn Blackmon
FROM	Brian Rybarik
CC	Charlie Inman, Heather Moline
DATE	November 7, 2025
SUBJECT	Data Center Workgroup - Minority Reports

To the organizers of Governor Ferguson's Data Center Workgroup,

First, I want to express my appreciation for the members of the workgroup, each of whom have brought important information to that table – resulting in good and, at times, challenging conversations. The many perspectives helped us better understand the facts and the implications of various proposals offered during this process. The discussions helped to focus attention on the opportunities and challenges associated with continued growth of the data center industry in Washington as we continue an energy transition, focus on reliability, and emphasize affordability for all utility customers.

I support the package of recommendations approved by the workgroup – but write to identify nuance with several of the recommendations and to provide comment on one recommendation that was not approved by the workgroup.

Recommendation #2 – Minority Report

I support this recommendation. If approved, the UTC has a variety of ways to fulfill the goal of developing practices to protect consumers, including through a policy docket, where we can convene stakeholders and develop a record to identify the best solutions for the state's investor-owned electric utilities.

While I believe the UTC has the authority to fulfill the goals of this recommendation, as noted at the workgroup meetings, these are policy issues on which the Legislature may want to provide input. I stand ready to work with the Legislature to provide information as needed.

Recommendation #3 – Minority Report

I highlight this recommendation to highlight the value of using incentives to innovate. We heard from data center companies that designing and operating flexible resources would be difficult and may not fit with current business models. Recent studies, however, quantify the benefit of large load flexibility to manage utility peak usage, finding that with flexibility requirements, nearly 100 GW of large new loads could be integrated with minimal impact, supporting economic growth while maintaining grid reliability and affordability.[1]

[1] Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems | The Nicholas Institute for Energy, Environment & Sustainability

Washington is an innovation-forward state. This recommendation seeks to enable innovation in technology and data center operations to better use the grid we already have.

Recommendation #5 - Comment

Though it was not adopted, I support the goal of this recommendation to apply tax incentives in order to advance data center expansion while also helping Washington meet its goals of equity and clean energy, a true win-win. Indeed, with respect to clean energy, the goal is to ensure that load growth from data centers respects and hastens the clean energy requirements applied to all electric providers in the state. Considering that most large data center providers have sustainability commitments that are consistent with Washington policy, such an incentive should benefit all parties.

The discussion on this item suggested that there wasn't enough detail to understand how a tax incentive for new clean energy or transmission could work. Lack of detail now is not a reason to abandon the concept in the future. I encourage the Governor and policymakers to continue this discussion and develop the details necessary to advance these concepts, and I stand ready to assist in that work.

Recommendation #6 – Minority Report

I highlight the importance of this recommendation, as it is the foundation of all utility planning, which is the basis for utility infrastructure decisions. If we have bad forecasts, we make bad decisions, which have reliability and cost implications for all customers.

In an era where forecasts were consistent and showed relatively low increases in electricity demand and usage, this was not an area of focus. Today, we see increasing and widely varying load forecasts, with the Northwest Power and Conservation Council predicting a potential to double average electricity demand by 2046 and almost a doubling of peak demand.[2] Nationally, McKinsey predicts an increase in data center loads from approximately 25GW today to over 80GW by 2030, consuming about 12% of U.S. electricity production at that point.[3] Wood Mackenzie estimates that the Data Center pipeline exceeded 92 GW at the end of 2024, nearly double the peak load of the California Independent System Operator.[4]

Forecasts are never exact – but it is critical that we focus attention on this baseline issue.

Recommendation #8 – Minority Report

I support this recommendation but write to encourage that Executive Order 25-10 be added as a reference in the second bullet point. Signed at the recent Centennial Accord meetings, which I was honored to attend, the Governor's direction is clear: tribal consultation is a required and essential part of any process of state government.

---

[2] Council releases initial 20-year forecast for Pacific Northwest electricity demand

[3] Data centers and AI: How the energy sector can meet power demand | McKinsey

[4] Data center pipeline capacity exceeds 92 GW by end of 2024, says Wood Mackenzie | Wood Mackenzie

Recommendation #9 – Minority Report

This recommendation is focused on advancing the development of emerging technologies – and therefore the focus is on support for more nascent technologies that are more dispatchable than wind and solar. That said, wind, solar, and short-duration storage options have been commercialized, with costs continuing to come down. This recommendation should not diminish the place these resources have in the solution set to meet the state's clean energy goals.

With respect to the direct access programs identified in this recommendation, this should be an option to meet energy needs, but not necessarily the rule. While direct access has appeal when faced with large energy users that can impact the grid for all – the utility provider model has proven effective to protect consumers and ensure reliability. Targeted use of direct access may be beneficial, but we should be careful not to make wholesale changes.

TO: David Duvall, Dept of Revenue (davidd@dor.wa.gov)
CC: Heather Kurtenbach, Executive Secretary, Washington State Building and Construction Trades Council heather@wabuildingtrades.org
RE: Joint Minority Report for Data Center Workgroup Final Findings and Recommendations

David,

Our organizations remain opposed to any policies that would negatively impact the responsible construction of data centers in Washington State. If the state were to impose policies that disincentivize data centers – effectively blocking these projects – it would eliminate one of our only consistent sources of family-wage, union construction jobs. More importantly, we would be distracting from the state's actual crisis: a failure to build clean generation, storage, and transmission.

The need for data centers will continue. If Washington enacts policies that are too restrictive to this specific industry, projects- and their economic benefits- will simply be pushed to other states with weaker or nonexistent labor protections, lower safety standards, and significantly weaker environmental safeguards.

With existing grid constraints, Washington should balance implementing reasonable regulatory measures on all large load users and accelerating the buildout of clean energy generation and transmission. Washington's data infrastructure can and should be powered by clean electricity—but that will only be possible if the state removes barriers to new utility-scale renewable projects and streamlines the permitting process.

Below are our minority responses to the recommendations finalized at the data center workgroup meeting. Additionally, we include reasonable policy solutions that prioritize working people across the state by ensuring that we can continue to bring union jobs to Washington.

Minority Responses:

Recommendation 3

This recommendation singles out a specific industry that already operates under our state clean energy laws. Imposing duplicative requirements will disincentivize data center development in our state.

Washington's existing clean energy framework already governs how large energy users plan, procure, and report their energy use and emissions. Data centers are subject to these requirements through their utility providers, which must meet our 100% clean energy and greenhouse gas reduction mandates. Additional sustainability report mandates would create redundant administrative burdens without yielding meaningful new environmental benefits.

Furthermore, this recommendation does not include a clear strategy for protecting or expanding clean energy jobs in Washington. By targeting data centers for additional reporting and compliance costs, the proposal could discourage job creation for our construction trades.

Lastly, incentivizing load flexibility can likely be achieved more effectively through existing utility programs and regulatory mechanisms. The Utilities and Transportation Commission (UTC) already have the authority to promote demand response and energy efficiency programs, and many utilities are actively piloting flexibility solutions that include large commercial customers. It would be worthwhile to have the state put these requirements into statute for the non-IOU utilities as well.

Recommendation 4

Much of the analysis and mitigation framework described here is already well established under existing state law and agency practice. Washington's State Environmental Policy Act (SEPA) already provides a comprehensive process for evaluating and mitigating the types of impacts identified in this recommendation.

Additionally, the Department of Ecology and other state and local agencies already maintain extensive expertise, data, and regulatory tools in these areas, including water rights administration, discharge permitting, and air quality management. Ecology's existing programs are well-positioned to address the environmental impacts of data center operations without the need for a study.

Recommendation 9

We support advancing clean energy technologies, but Washington has not yet been able to accelerate deployment of emerging resources like geothermal, long-duration batteries, or advanced nuclear.

Additionally, requiring data centers to source their own power risks moving investment and jobs out of state and incentivizes clean energy built elsewhere. Any such programs should ensure that clean energy growth and economic benefits remain in Washington.

Lastly, without labor protections for behind-the-meter generation, our workforce loses current and future jobs.

Policy Recommendations:

1. **Implement a Statewide Green Tariff for Large Energy Users**
   Establish a green tariff program for electricity customers exceeding a specified megawatt (MW) threshold. This tariff would ensure that the costs associated with energy consumption and infrastructure development for all large load customers, including data centers, are not transferred to general ratepayers, while providing large users access to renewable energy options. Require the non-IOU utilities similarly.

2. **Adopt Time-of-Use (TOU) Electricity Rates**
   Introduce or expand time-of-use rate structures that align electricity pricing with periods of high and low demand. This policy would encourage large users, to the extent possible, to improve

energy efficiency measures reducing strain on the power system.

3. **Develop Clean Backup Power Incentives**
   Require large energy users to cover application fees for new service connections and for permitting backup generation systems. Incentivize the adoption of battery storage and other clean backup technologies by imposing higher fees or stricter standards on diesel generators.

4. **Address Natural Gas Use and Carbon Allowance Allocations**
   Review and revise policies governing the use of natural gas in large facilities. Reevaluate the allocation of free Cap-and-Trade (CCA) allowances to ensure they are aligned with state decarbonization goals and do not unintentionally subsidize fossil fuel use.

5. **Establish a Clean Energy Impact Contribution**
   Create a small, per-kilowatt (kW) or per-megawatt (MW) impact rate for large-scale electricity users, with proceeds deposited into the statewide Weatherization and Energy Efficiency (EE) Fund administered by the Department of Commerce. These funds support residential energy efficiency improvements, ensuring that large users contribute to broader energy resilience and equity goals.

This minority opinion reflects our continued belief that Washington's approach to data center policy must remain balanced, pragmatic, and focused on solutions that support both family-wage jobs and clean energy development.

We recognize that data centers are energy-intensive, but they are also one of the few consistent sources of union construction work and long-term economic investment in communities across the state. Rather than imposing restrictive policies that risk driving these projects—and their associated jobs—elsewhere, Washington should focus on responsible, transparent regulatory mechanisms that target all large load users in the state while accelerating clean power generation, transmission, and storage. Doing so will ensure that our state continues to meet its ambitious climate goals while maintaining its commitment to Washingtonians to provide good jobs, fair labor standards, and sustainable economic growth.

Sincerely,

Cassie Bordelon

Cassie Bordelon, Executive Director
Climate Jobs Washington

Heather Kurtenbach

Heather Kurtenbach, Executive Secretary
Washington State Building and Construction Trades Council

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600, Olympia, WA 98504-7600 • 360-407-6000

November 7, 2025

TO: David Duvall, Department of Revenue

FROM: Diane Butorac, Department of Ecology

SUBJECT: Washington Department of Ecology Minority Report on the Data Center Workgroup Recommendations

Workgroup recommendations:

1. **Maintain the integrity of Washington's climate laws.**
4. **Protect community, Tribal, and environmental resources.**
8. **Accelerate siting and permitting of transmission and clean energy generation.**
9. **Accelerate the deployment of existing and emerging technologies, such as geothermal energy, green fuels, long-duration batteries, and nuclear energy to provide data centers with firm energy.**

The Department of Ecology (Ecology) appreciates the opportunity to participate on the Data Center Workgroup and on the Energy and Resource Impacts subgroup. This process helped identify timely and relevant issues and concerns and allowed for the development of findings and recommendations through collaboration among parties with multiple interests.

We are submitting this minority report to emphasize Ecology's continued support for our transition to clean energy while protecting the environment and growing the economy. These recommendations can help data centers move the clean energy transition forward in Washington through new renewable energy development and innovative solutions.

Washington State is a leader in clean energy; yet today we face historic challenges to securing our energy future. To support the growing demand for electrification and large load energy users like data centers, we must take action to rapidly build transmission and generate new renewable energy. Without a coordinated state effort, we face a future of unreliable electricity, higher energy costs, and climate impacts to our people and environment.

Washington's energy and climate policies, as well as its growing economy and population, require significant additional investments in clean energy resources, including electric generation, storage, and transmission assets. The Climate Commitment Act (CCA) and Clean Energy Transformation Act (CETA) set statutory requirements for reducing fossil fuel use.

Washington's energy picture is made more complex by the projected rapid growth of large electricity users, such as data centers. This growth is happening quickly and was not part of long-term resource planning by utilities. The need for new transmission to manage the state's electrification goals is not a new issue, but the unprecedented growth by data centers and the large amount of power that they need has exacerbated the demand upon the system.

To address the lack of transmission capacity in the near-term, multiple data center developers have shared proposals with Ecology to use fossil fuels as the main source of their power. These are mainly "behind the meter," meaning the energy is for their facilities to use directly and not through the electrical grid managed by utilities. The Legislature established CETA to transition the state's electricity supply to be greenhouse gas neutral by 2030. Very few data center developers are proposing to use clean energy to meet their energy needs over the next five years. Several data center developers expect to meet future needs using small modular nuclear reactors or fossil fuel projects with carbon sequestration. While these may be options, there are concerns over the feasibility of these new technologies as they are still in the early stages of research and design and they do not address the immediate need for energy.

Data centers could help move the clean energy transition forward in Washington through new renewable energy development and innovative solutions. We supported a recommendation to tie clean energy development to tax incentives in Washington, but this was not adopted by the workgroup. There is value in ensuring existing clean energy policies are implemented effectively and in considering how to additionally incentivize renewable energy development. Data center developers could support the clean energy transition in multiple ways, such as bringing their own clean power generation, through a power purchase agreement for new clean power capacity, or making contributions to improve grid capacity or transmission. Data centers have contributed to developing clean energy as part of the grid or behind the meter, however, we are concerned with the multiple current proposals in Washington that only consider fossil fuel options and dependence on unproven technologies for the future.

Ecology also stated concerns that rapid growth in energy use from data centers, if supported by fossil generation, would impact the state's ability to meet its statutory greenhouse gas limits. The allowance market within the Cap-and-Invest Program, authorized by the CCA, sets its allowance supply consistent with Washington's statutory greenhouse gas limits. If data centers use fossil fuels as a significant source of power, this would increase overall demand from limited and declining economy-wide allowance supply. Rapid increases in allowance demand are likely to increase the price of allowances until commensurate emission reductions elsewhere in the economy can be achieved. Additionally, depending on how data centers purchase power, they could greatly expand the retail load of local utilities. If utilities do not serve data centers with clean energy, no-cost allowances allocated to electric utilities could increase. No-cost allowances provided to electric utilities are intended to mitigate the cost burden of the Cap-and-Invest Program on retail electric customers, protecting Washington residents from potential rate increases. But increasing no-cost allowance allocation to electric utilities to meet data center load could restrict allowance supply at auction, raising auction prices for all participants.

During the workgroup process, Ecology raised concerns over potential environmental impacts from data center development, especially when there are multiple new facilities in a small area that could lead to cumulative impacts. The use of fossil fuels for main power and emergency back-up power as well as refrigerant gases could affect air resources and communities. Cooling systems can use large amounts of water and energy which can affect local water systems, Tribal resources, and energy costs. The workgroups had many discussions about these issues and while some data centers are using or planning to use state-of-the-art technologies, others are not. We highly recommend developers engage early with Tribes and communities to identify concerns and attend pre-application meetings with agencies to help understand permit requirements. These types of early engagement can help avoid and minimize impacts.

We support growing our economy in a way that ensures a healthy environment, meets our energy and climate obligations, and benefits all of Washington. We must take action to rapidly build transmission and generate new clean energy to minimize emissions and support not only data centers, but improve reliability and resiliency across our electrical grid and to keep electricity affordable for Washington families.

Matthew Hepner

East Wenatchee City Council position 7.

Local Government

Mr. David Duvall.

Local governments like East Wenatchee strongly support responsible data center development because these projects deliver sustained local economic benefits: family-wage construction and operations jobs, predictable long-term tax revenue, expanded business activity, and investments in public services and infrastructure.

Executive summary

- Data center construction has been a major driver of local economic development — creating union construction jobs, permanent operations employment, and multiplier effects for suppliers, contractors, and local businesses.
- Blocking or constraining the industry will shift investment to other states taking revenue away from local governments here at home.
- The real statewide constraint is insufficient clean generation, storage, and transmission capacity — not the existence of digital infrastructure like data centers. Policy should focus on accelerating clean energy buildout and modernizing the grid while ensuring fair cost allocation and protections for ratepayers and communities.
- Local governments favor targeted, practical policy tools that allow communities to capture benefits, mitigate impacts, and ensure projects are responsibly sited and powered by cleaner resources.

Local government framing of core findings

- Economic and workforce impacts: Data centers support thousands of direct construction jobs and additional long-term local employment (e.g. facility operations, facility services, local suppliers). They provide stable, taxable commercial activity that funds local services—public safety, roads, schools, and utilities—without the volatility of some other industries.
- Fiscal benefits: Property taxes, business & occupation taxes, permit fees, utility hook-up fees, hotel motel tax, and other local revenues from data centers provide reliable revenue streams that help stabilize municipal budgets and reduce pressure on residential taxpayers.
- Community and environmental impacts: Local governments like East Wenatchee acknowledge potential impacts — water demand, land use changes, traffic during construction, cultural and environmental concerns — and assert that these are manageable with early coordination, mitigation measures, and conditions established through local permits, SEPA, and interlocal agreements.

- Regional competitiveness and leakage risk: Excessively onerous or unpredictable statewide restrictions will redirect projects to other jurisdictions, reducing regional investment and potentially sending jobs to states with less robust worker and environmental protections.

Local government priorities

- Promote balanced growth: Encourage data center investment that expands local jobs and revenues while safeguarding water, cultural resources, and the environment through local review, mitigation, and community benefit agreements.
- Share costs fairly: Ensure new large load users pay for their direct interconnection, distribution, and local system upgrades so costs aren't shifted to other ratepayers or residents.
- Accelerate clean energy: Prioritize policy and permitting changes that speed clean generation, storage, and transmission so data centers can be powered with low-carbon electricity without constraining local development.
- Preserve local authority: Maintain local land-use and permitting roles so communities can negotiate siting, mitigation, and community benefit conditions tailored to local needs.
- Transparency and coordination: Standardize reporting and early notification from applicants to utilities, local governments, and Tribes to identify impacts and mitigation early.

Recommended actions for the Governor, Legislature, and state agencies

1. **Accelerate clean generation and transmission buildout**

- Prioritize removal of permitting and siting barriers for renewable generation, long-duration storage, and transmission projects (streamlined permitting timelines, coordinated environmental review, and siting councils working with local governments and Tribes).
- Establish a state entity or strengthen an existing authority to coordinate transmission planning, siting, financing, and land acquisition to reduce local friction and deliver projects faster.

2. **Require fair cost allocation and local protection measures**

- Adopt rules ensuring new large loads (threshold by MW) pay for direct interconnection, required distribution upgrades, and any local system impacts through application/service extension charges or similar mechanisms.
- Encourage development of model tariffs and contract terms (by UTC and public utility boards) that define MW thresholds, commercial readiness criteria, credit requirements, and interconnection cost responsibility so localities and ratepayers are protected.

3. **Design green-tariff and procurement pathways benefitting local communities**

- Create statewide green-tariff options enabling large loads to fund investment in local and regional clean resources (e.g., long-duration storage, geothermal, community-scale renewables) with mechanisms to avoid cost shifts to other ratepayers.

- Allow municipalities and special districts to negotiate community benefit investments as part of green tariff or tax-incentive packages (workforce training, affordable housing, energy efficiency programs).

4. Strengthen workforce and local hiring commitments

- Promote and condition incentives on local hiring, apprenticeship utilization, prevailing wages, and project labor agreements for construction to ensure community job access and quality employment.
- Fund apprenticeship systems so local residents can access the construction and operations jobs generated by data centers.

5. Improve resource forecasting, transparency, and readiness standards

- Standardize reporting requirements across utilities for new large load applications (common data format, timing, and disclosure of aggregations/duplicative requests). This helps local governments, utilities, and Tribes plan water, wastewater, transportation, and emergency services.
- Establish commercial readiness and queue-entry criteria to reduce speculative interconnection requests that complicate local planning.

6. Manage water, land-use, and environmental impacts locally with state support

- Require data centers to publish sustainability reports before construction showing energy and water balance, cooling technology, and plans for effluent management; require annual water-use reporting to the state.
- Fund state-local technical assistance and grants to help smaller jurisdictions evaluate potential cumulative impacts on water supplies, habitat, and cultural resources and to implement mitigation (e.g., water reuse, alternative cooling, infrastructure upgrades).
- Direct Ecology to develop best practices for siting and operating data centers with local governments, Tribes, and permitting agencies focused on water, air, and cumulative impacts.

7. Protect Tribal rights and cumulative impacts

- Require early, funded engagement with Tribes and local communities in site selection and permitting processes to identify treaty and cultural resource impacts and appropriate mitigation.
- Use cumulative-impact assessments when multiple large loads are proposed in a single watershed or region, and require mitigation or staged development where impacts exceed local resource capacities.

8. Model policy tools local governments support

- Green tariff statewide for large loads (MW threshold) that funds local/regional clean generation without shifting costs to residential ratepayers.

- Time-of-use and demand-flexibility incentives to reduce peak grid stress and create value for communities (e.g., grid services revenue shared regionally).
- Per-kW or per-MW deposits/fees earmarked for statewide weatherization, energy efficiency and local community resilience funds (administered by Commerce).
- Application, service-extension, and interconnection fees payable up-front and refundable only upon demonstrated progress toward commercial readiness to discourage speculative projects.

Conclusion

Local governments are not asking to block data center development; we strongly support responsible projects that create family-wage jobs, predictable revenue, and lasting local economic benefit. But that support depends on policies that: (1) ensure data centers pay their fair share for the local and grid costs they impose; (2) accelerates the clean generation, storage, and transmission needed to power them and the local communities; (3) preserve local land-use authority and community safeguards; and (4) guarantee workforce opportunities and tribal consultation. Washington can and should be both a national leader in clean energy and a competitive, fair place for data center investment — if state policy focuses on system-wide solutions rather than singling out one industry for restriction.

Requested coordination items

- Provide a consolidated data request on how many GW of new clean generation and utility-scale projects have been developed in the last five years, and current shortfall estimates relative to modeled needs for new large loads.
- Develop joint UTC-Commerce guidance for standardized reporting on large-load applications to help local governments and Tribes assess cumulative impacts early.
- Fund a state-local technical assistance pool to support jurisdictions facing potential cumulative impacts from clustered data center proposals.

From: Cameron Steinback, Front and Centered | cameron@frontandcentered.org
To: David Duvall, Chair, Data Center Workgroup | davidd@dor.wa.gov

Subject: Data Center Workgroup Minority Report - Finding #20

Finding #20 - General permits and general orders can reduce project timelines and ensure state regulatory requirements are met. These measures allow a proposed project to use pre-evaluated conditions and criteria and take less time than an individual permit.

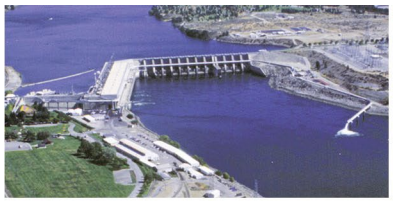
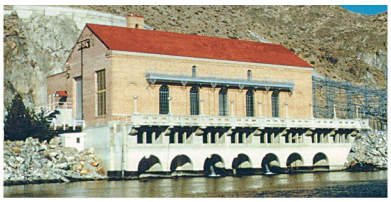
a. Ecology has existing general permits for water discharges and is developing a general order for data center emergency engine operations.

Front and Centered expresses our concern that general orders, specifically those permitting emergency backup generators, pose the significant risk of overlooking cumulative impacts. Even with additional conditions, including best available mitigation for emissions, testing and monitoring requirements, and a specific geographic scope, accelerating siting and permitting through general orders limits the already minimal opportunities for impacted communities to have their priorities included in formal review processes. SEPA's environmental review processes are necessary to assess the disproportionate harms experienced by frontline communities and give agencies and communities the necessary data to meaningfully engage in permitting decisions. SEPA also formalizes opportunities to intervene when potential impacts are identified and requires a certain level of transparency through public comment periods, public hearings, and agency responses to comments. Failing to preserve these types of safeguards when developing ways to accelerate and streamline both administrative and developmental processes related to permitting and siting will likely perpetuate disproportionate negative environmental and health outcomes.

For example, an air quality general order was proposed for data centers near the cities of East Wenatchee, Malaga, and Quincy. The general order would cap installation of emergency diesel generators at 21 per site. This is a substantial quantity, given the expected expansion and growth of data centers in the region. To contextualize the potential emissions that could result from the installation of diesel engines at this scale, a health impact assessment for 13 extra generators at the Sabey Data Center in Quincy found that the additional generators will create over 9 tons of NOx, 2 tons of PM 2.5M, and 2 tons of PM 10 with almost a ton of NO2 and diesel exhaust particulates.

The determination for the air quality general order is based on incomplete data, and a determination of non-significance has precluded the requirement of an environmental impact statement under RCW 43.21C.030(2)(c). Problematically, the completed environmental checklist does not account for the projected increase in data centers and accompanying emissions from other emergency generators, or the proximity to vulnerable, overburdened communities or sensitive locations such as schools or hospitals, since site-specific data is unknown under these types of general orders.

While opportunities for input are available periodically during general order renewal periods, public comments and potential mitigation is assessed as part of the broader category that the facilities belong to rather than on a site-specific level. This eases the burden for facility owners, developers, and state agencies by making these processes faster and simpler, but creates new barriers for frontline communities by making it more difficult to provide input on localized impacts and harms related to specific facilities. Given that future data center emissions may account for a majority of overall diesel emissions in areas covered by the general order, such as Quincy, there is a clear need for greater attention to cumulative impacts and protecting public participation requirements, which must be upheld as accelerated permitting and siting processes are developed.


PUBLIC UTILITY DISTRICT NO. 1 of CHELAN COUNTY
P.O. Box 1231, Wenatchee, WA 98807-1231 • 203 Olds Station Rd., Wenatchee, WA 98801
(509) 663-8121 • Toll free 1-888-663-8121 • www.chelanpud.org

November 7, 2025

Governor Bob Ferguson
Office of the Governor
PO Box 40002
Olympia, WA 98504-0002

RE: Chelan PUD's Minority Report to the Governor's Data Center Workgroup

Dear Governor Ferguson,

Thank you for convening the Data Center Workgroup to examine how Washington can responsibly balance the rapid growth of data centers with the state's clean energy goals, electric grid reliability, and long-term affordability.

On behalf of Chelan County Public Utility District (PUD) and our customers, it has been a privilege to serve as a member of the full Workgroup and the Energy & Resource Impacts Subgroup. Chelan PUD's structure and history give us a unique vantage point on data center development. We understand both the opportunities and the risks that these large energy users present, and we're committed to helping shape strategies that address these challenges.

Unfortunately, several of the Workgroup's adopted recommendations fall short in addressing core system challenges and, in some cases, risk undermining the governance and regulatory models that have served our communities well for nearly 100 years. Chelan PUD respectfully submits this Minority Report to record the concerns of public utilities and our customers, offer constructive alternatives, and underscore the need for practical, locally grounded solutions.

About Chelan PUD

Unlike most public utility districts in Washington, Chelan PUD does not purchase power from the Bonneville Power Administration. We are a power generator. We own and operate one of the largest non-federal hydropower systems in the nation.

COMMISSIONERS: *Kelly Allen, Garry Arseneault, Carnan Bergren, Steve McKenna, Randy Smith* GENERAL MANAGER: *Kirk Hudson*

Roughly 20 percent of the energy we produce serves our 52,000 retail customers within Chelan County. The remainder is sold to regional partners, including Puget Sound Energy and Avista. The power generated by Chelan PUD helps keep the lights on in the Puget Sound area and Spokane. This generation capacity has long allowed Chelan PUD to remain energy self-sufficient. However, we are now facing an unprecedented wave of demand growth, driven largely by large load requests from data centers.

The PUD's current average annual load is about 228 average megawatts, yet our interconnection queue includes requests totaling an additional 1,428 megawatts. While not all these projects will materialize, the scale of potential growth represents a fundamental shift for our utility. Our 2023 Integrated Resource Plan progress report forecasts total load increasing by 230 percent between 2023 and 2032, an unprecedented increase.

This transformation has implications not only for Chelan PUD but also for the state's energy system as a whole. More local consumption reduces the surplus power we sell on the wholesale market. That energy is used by other utilities in the state to meet their clean energy obligations, and it generates revenue for the PUD that allows us to keep rates affordable.

Recognizing these dynamics, our Board of Commissioners adopted a set of guiding principles for evaluating data center and other large load requests, with a focus on maintaining reliability and rate stability for existing customers.

Within this framework, Chelan PUD has built productive partnerships with data center developers, including Microsoft, which constructed a new facility in Chelan County this year. Through careful planning, we have created the conditions for responsible technology growth, attracting investments that align with our long-term vision.

Chelan PUD is also looking ahead to the next frontier of clean energy. Our collaboration with Helion embodies that spirit of innovation – a bold step toward harnessing fusion power and redefining what's possible in sustainable energy generation – and we continue to evaluate potential geothermal generation.

This progress underscores the power of local utility governance. The ability to design utility-specific policies – like our large load framework – has been central to our success navigating the new energy landscape. It's a model that demonstrates how local decision-making can balance economic opportunity, environmental stewardship, affordability, and public accountability.

The Resource Adequacy Challenge

While our experience shows that clean, reliable, community-centered growth is possible, across the Northwest, the energy system is under immense pressure. As data centers and other energy-intensive industries expand to power the digital age, they are putting a new level of strain on resource adequacy. Firm generation is retiring, new resources are slow to arrive, and the once-stable grid is being tested in ways it has never been before.

The Pacific Northwest Utilities Conference Committee in its 2025 regional forecast projected a load-growth increase of more than 30 percent by 2034 – a dramatic shift that will test the region's generation and

transmission capacity. A recent Energy + Environmental Economics (E3) study found that without consequential action to address the widening gap between future energy demand and supply, our region faces the possibility of rolling blackouts as soon as next year in extreme conditions. Ensuring resource adequacy, while also containing rapidly increasing energy costs that are straining family budgets, is a critical challenge that requires bold solutions.

Washington must adopt a coordinated, long-term strategy that ensures generation and transmission development stay ahead of demand, and the time to act is now. The choices made in the next five years will determine whether this period becomes one of scarcity, or transformation.

We strongly believe state policy should enable, not impede, utility-led action by aligning timelines, streamlining permitting, and removing barriers that slow the development of new, clean energy resources. Ensuring a resilient clean energy future will depend on giving utilities the flexibility and certainty to do what they do best: plan, build, and operate the systems that keep Washington powered.

To that end, Chelan PUD urges the state to resist expanding its role or administrative footprint through the creation of new offices and agencies and instead focus on removing policy and process barriers. We ask that the state take decisive action in the following areas:

- Streamline siting and permitting: Accelerate approval of new clean energy generation and transmission projects.
- Reevaluate clean energy policy timelines: Provide additional flexibility in interim compliance targets to ensure utilities can meet statutory clean energy goals while preserving reliability and affordability.
- Support firm resource technologies: Prioritize investment and incentives for scalable firm resources such as advanced nuclear, long-duration storage, and geothermal, and remain open to natural gas as a bridge to our clean energy future.
- Improve load forecasting: Strengthen coordination and transparency in large load forecasting to avoid over- or under-investment.
- Preserve local ratemaking authority: Uphold the autonomy of consumer-owned utilities to design rates and policies suited to their systems and communities.

Chelan PUD is encouraged that the Governor's Office and leadership at state agencies such as Commerce and Ecology are openly acknowledging and thinking through ways to address the magnitude of the resource adequacy challenge. This growing recognition marks an important and positive step.

However, while the Data Center Workgroup's findings and recommendations acknowledge these concerns, the adopted recommendations do not directly address their underlying causes and miss the opportunity to advance meaningful solutions.

Chelan PUD's approach to data center growth is simple: to plan for tomorrow with intention and act as good ancestors for the generations that will inherit the systems we build today. That perspective has informed my participation in Workgroup discussions throughout this process, as well as the PUD's positions on the following Workgroup recommendations.

(Note: We support the overarching goals of these recommendations. However, many of the sub-bullets propose actions that do not reflect the realities utilities face in planning and operating reliable systems. These are complex, interdependent systems that demand both technical understanding and practical experience. My comments are offered from that experience – affirming the intent of the recommendations while clarifying where priorities raised by various interests on the Workgroup conflict with the practical demands of power generation and delivery.)

Recommendation 1: *Maintain the Integrity of Washington's Climate Laws*

- *Ensure Washington's Climate Commitment Act and Clean Energy Transformation Act operate as envisioned to cover any fossil or unspecified power sources used by large data centers.*

Chelan PUD Position: Do not support

Chelan PUD remains committed to Washington's clean energy and carbon-reduction goals and supports the intent of the Clean Energy Transformation Act (CETA). However, this recommendation risks enshrining inflexible policies that fail to adapt to real-world system conditions and emerging technologies.

To ensure long-term grid stability in the face of rapid large load growth and to protect affordability, the state must maintain flexibility in policy implementation. A responsive, evidence-based regulatory framework will keep the energy transition grounded in operational realities and safeguard customers' access to clean, affordable, and dependable electricity – vital for public health, safety, and daily life. This adaptability is also essential to maintaining public trust in the state's clean energy transition.

Recommendation 2: *Strengthen ratepayer protections.*

- *Require the UTC and consumer-owned utilities develop model tariffs or model contracts for a new rate class that: (1) identify a MW threshold for the tariff serving new large loads; (2) specify the characteristics of these new loads; (3) require new large loads pay for the direct interconnection costs caused by their interconnection; (4) require new large loads cover any costs of generation, transmission or distribution systems required to serve new large loads and avoid shifts of costs or risks to other customer classes, including potential stranded assets.*

Chelan PUD Position: Do Not Support

There are several positive concepts in this recommendation that Chelan PUD supports in principle, particularly the emphasis on ensuring new large loads pay for their fair share of interconnection and system upgrade costs. Chelan PUD has recommended to the Workgroup that data centers make meaningful financial commitments, including paying a portion of grid upgrade costs upfront. Many consumer-owned utilities, including Chelan PUD, already include provisions in their contracts requiring customers to cover direct interconnection costs.

However, requiring consumer-owned utilities to develop model tariffs or contracts in a prescribed manner would undermine the ratemaking authority of locally elected utility commissions. Each utility has unique

resource portfolios, system constraints, and customer priorities. A top-down, statewide model would erode this governance structure and limit our ability to craft rate solutions tailored to local needs.

The state's role should be to support coordination, data-sharing, and transparency – not to prescribe contract terms.

Recommendation 3: *Incentivize load flexibility and best practices for energy efficiency.*

- *Direct agencies to identify, incentivize, and unlock the potential for load flexibility, particularly from large data centers. Incentives could include specific tax incentives or faster interconnections for large loads that are able to participate in demand response programs or those that help fund demand response and energy efficiency for low-income households and other customers.*
- *Require data centers to publish a sustainability report prior to construction that demonstrates how the data center balances energy, water, and computing performance. Require the report to be updated when replacing equipment.*
- *Fund the Energy Policy Office to conduct a study on the potential to meet data center loads with on-site energy generation or storage, demand response programs, or load management programs, and include recommendations on any program or policy changes that may be needed to achieve the potential.*

Chelan PUD Position: Do Not Support

Chelan PUD agrees with the importance of maintaining operational flexibility to ensure system reliability, particularly given the grid's limited reserve margins during extreme conditions. We support demand management and flexible load practices through utility-specific programs. However, we oppose state-level incentive structures that override consumer-owned utility discretion and conflict with the public utility principle of local decision making. Again, each utility has unique resource portfolios, system constraints, and customer priorities.

Recommendation 4: *Protect community, Tribal, and environmental resources.*

- *Direct and fund the Department of Ecology to conduct a study and develop best practices for siting and operating data centers with input from permitting agencies, industry, Tribes, interested parties, local government, and utilities. The study will address:*
- *Water resources, including water availability, water quality impacts, direct and cumulative impacts on the local water system, and potential for discharges that cause a municipal water system to exceed its capacity resulting in untreated water entering streams or rivers;*
- *Impacts to Tribal rights and resources; and*
- *Air resources, including greenhouse gas emissions and direct and cumulative air emissions.*
- *Replace the data center sustainability provisions in existing law [such as RCW 82.08.986(4)] with a standard that more specifically encourages energy and water efficiency at newly constructed data centers.*
- *Require data centers to report water use annually to the state. The report should include daily quantities (total and peak uses) and any effluents that are discharged outside the data center.*

- *Encourage the Northwest Power and Conservation Council (NPCC) to incorporate the anadromous fish managers' recommendations on the spill and reservoir operations at the dams into the Columbia Basin Fish and Wildlife Program. The NPPC would then incorporate those operations into the development of the next Pacific Northwest Conservation and Electric Power Plan*

Chelan PUD Position: Do Not Support

Protecting community, Tribal, and environmental resources is central to Chelan PUD's mission and reflected in the work we do every day. However, this recommendation as written conflicts with federal law and existing hydropower licensing frameworks.

The Federal Energy Regulatory Commission (FERC) maintains exclusive authority for licensing and oversight of non-federal hydropower projects, including all environmental mitigation and fish and wildlife conditions. As part of its responsibilities under the Federal Power Act (FPA), FERC determines appropriate protection, mitigation and enhancement (PM&E) measures to ensure that licensed hydroelectric projects are "best adapted to a comprehensive plan for improving or developing a waterway or waterways" across the spectrum of public and natural uses, including hydropower generation, PM&E of fish and wildlife resources, recreation, water supply, navigation, and irrigation. Under the FPA, all licensed conditions to achieve this balance under are included in each project's federal operating license.

Directing the state to impose additional resource conditions through separate processes risks duplication and regulatory conflict.

Chelan PUD supports collaborative engagement among the state, Tribes, and licensees within the FERC framework but cannot endorse a recommendation that compromises established federal jurisdiction and existing agreements.

Recommendation 7: *Enhance transmission capacity.*

- *Create a state entity to support the development of transmission projects, which could include permitting, land acquisition, finance and even construction.*
- *Direct agencies to prioritize upgrades to existing transmission lines with grid enhancing technologies.*

Chelan PUD Position: Do Not Support

Chelan PUD strongly supports increasing transmission capacity across the state but creating a new state authority is not the solution.

Establishing new bureaucracy could add administrative complexity without addressing the true barriers to infrastructure development: permitting delays and regulatory uncertainty. The state's most constructive role would be streamlining permitting, facilitating federal-state coordination, and ensuring that cost allocation and planning processes respect regional transmission governance.

We recommend the state work proactively with federal agencies to pre-permit transmission corridors on both state and federal lands. Pre-clearance of routes would expedite future transmission projects by completing much of the environmental and regulatory review in advance. We also support the categorical exemption for transmission upgrades that was included in SB 5466 as introduced in 2025.

Recommendation 9: *Accelerate the deployment of existing and emerging technologies, such as geothermal energy, green fuels, long-duration batteries, and nuclear energy to provide data centers with firm energy.*

- *Create a direct access program for new large loads in Washington to allow customers to source their own power.*
- *Design green tariffs for large data center companies to invest in innovative higher-cost clean energy resources, such as long-duration battery storage.*

Chelan PUD Position: Do Not Support

Chelan PUD supports the intent of this recommendation. We particularly emphasize the need to prioritize on-demand, dispatchable resources – technologies capable of providing firm capacity to maintain reliability as Washington is increasingly reliant on variable resources.

In addition to the technologies listed here, Chelan PUD believes natural gas with carbon capture must be recognized as a vital near-term resource, and we were disappointed it was left out of the final recommendation. It provides dependable capacity during periods of low renewable generation and protects public safety during extended cold-weather events. (For example, during the January 2024 cold snap, wind generation across the Pacific Northwest fell to nearly zero as demand surged. Solar and short-duration batteries also provided limited support, contributing less than 10–20 percent of their nameplate capacity compared with more than 90 percent for natural gas resources.)

Until other emerging technologies become commercially available and affordable at scale, natural gas will remain an important bridge.

We are also concerned that this recommendation includes the creation of a direct access program for large loads. Such a program would allow certain customers to bypass their local utilities and purchase power directly from the market. While that may sound like a way to expand choice, it would undercut the integrated planning, reliability management, and cost-recovery systems that keep Washington's public power model stable and affordable.

Buying power on the open market is only part of the challenge – delivering it requires access to a constrained transmission system regulated by FERC. Available transfer capacity (ATC) is already limited. Allowing direct access would force utilities and essential service providers to compete with global tech companies with far greater financial leverage for that scarce capacity. That imbalance could drive up costs, strain reliability, and push rates higher for everyone else.

At the local level, distribution systems are built and managed by locally elected utility boards. These systems are carefully planned and expanded to match community growth and keep rates affordable. Direct access

would erode this local control by forcing utilities to invest in costly system upgrades for large, market-driven loads. These costs would be borne by existing customers, and if large users later curtail operations or leave, communities could be left paying for stranded assets.

Utilities are best positioned to manage power delivery within their jurisdictions. Our model of local governance ensures accountability, transparency, and fairness – principles that could be compromised by one-size-fits-all market mechanisms like direct access

Once again, thank you for the opportunity to be part of the Workgroup and to provide input on such an important issue for the future of Washington State. Please let me know if there is an opportunity to discuss any of our concerns further.

Sincerely,

Kirk Hudson
General Manager, Chelan County PUD

The Nature Conservancy
Washington

Submitted electronically

November 7, 2025

David Duvall
Washington Department of Revenue
Olympia, WA 98504-7600

RE: Minority Report to the Washington Data Center Work Group Final Findings and Recommendations

Dear Mr. Duvall,

The Nature Conservancy (TNC) expresses our deep appreciation to Governor Ferguson, Governor's Policy Leads, Department of Revenue staff, and Department of Ecology staff for convening and shepherding the Washington Data Center Work Group to this stage of final Findings and Recommendations. I am grateful for the opportunity to have participated, to learn from others, and bring our perspective to the conversation.

TNC reflections on select findings and recommendations are below, and I'd like to note that TNC is part of separate joint submission with NW Energy Coalition and Front and Centered related to Recommendation #5 that I've also included in this Minority Report. We also encourage the Governor, agencies, state legislators, Work Group participants, and members of the public to give strong consideration to the Yakama Nation submission related to the Findings and Recommendations. We have engaged deeply with their representatives during the past few months and believe it is critical to be responsive to their thoughtful comments and the reserved Treaty rights of Sovereign Tribal nations.

Thank you for your leadership on this very important issue to Washingtonians, and for your consideration. Please feel free to contact me at (703) 340-7553 or justin.allegro@tnc.org if you have any further questions on our comments.

Sincerely,

Justin Allegro
Policy Director
The Nature Conservancy in Washington

74 Wall Street
Seattle, WA 98121
Tel: (206) 343-4344
www.WashingtonNature.org

Findings – Tax Revenue & Economic Development Subgroup

This section outlines the economic and fiscal impacts of data centers in Washington, including siting factors, tax incentives, job creation, and local infrastructure improvements. We are only commenting on one finding in this section.

Finding T.13 – Washington is falling behind in building out the infrastructure – generation, transmission, and battery energy storage — necessary to achieving the state's clean energy goals.

Comment: We think this is an important finding, which we agree with strongly. To be clear, falling behind does not – and cannot – mean that we should walk back from these targets. It simply means places more of an obligation on the state and on partners to figure out the necessary, integrated solutions to achieve this top priority.

Findings – Energy & Resource Impacts Subgroup

This section addresses the energy demands of data centers, their impact on the grid, environmental and tribal concerns, and regulatory challenges. Rather than specific comments on each individual findings, the Nature Conservancy wishes to express our support the findings "en toto". Why they may not be how we would write each section, we think they reflect well the situation. The lone area they TNC feels could have been better reflected was in capturing better the substance of the Yakama Nation's comments on these findings. We wish to express kudos to the Commerce staff and Governor's office for leading these findings.

Recommendations

These recommendations aim to align data center development with Washington's climate goals, protect communities, improve forecasting and transmission, and accelerate clean energy deployment.

Recommendation 1 – Maintain Integrity of Washington's Climate Laws

Comment: We support this recommendation with vigor.

Recommendation 2 – Strengthen Ratepayer Protections

Comment: We support this recommendation. There is substantial momentum in this arena from within other jurisdictions. We appreciated the Work Group conversation and specifically the

perspective of utilities and the UTC regarding the relatively unique set of management considerations associated with the connection and service requirements for most data centers.

Recommendation 3 – Incentivize Load Flexibility & Efficiency

Comment: We support this recommendation, but additionally we would prefer to see a direct connection in the tax incentives to minimum standards for demand response participation and energy efficiency, as well as water efficiency, given the rapid progress in this space that is seemingly in the news every day. Giving Commerce Energy staff the authority to determine appropriate levels based on available technology could be an approach. In light of existing resource adequacy challenges which will be exacerbated by the predicted demand of data centers, on-site and in-lieu (funding utility demand-response programs) is appropriate.

Recommendation 4 – Protect Community, Tribal, and Environmental Resources

Comment: We support this recommendation and also encourage further consideration of Yakama Nation and CRITFC recommendations.

Recommendation 6 – Improve Resource Forecasting
Comment: We support this recommendation.

Recommendation 7 – Enhance Transmission Capacity
Comment: TNC supports the recommendation. We believe a Transmission Development Authority can help identify gaps in the implementation of our planned transmission system, spaces that are more complex or have less ripe business interest incentives but are nonetheless essential sooner rather than later for a clean and connected grid necessary to meet our climate targets and provide more affordable, reliable energy to Washingtonians. An authority with the appropriate connection to full or partial public financing can both enhance transmission capacity and reduce costs on ratepayers at an unprecedented time of infrastructure buildout.

Finally, the recent Connected West study shows the potential for better utilizing existing transmission resources and deploying GETS, so we are grateful for that element of this recommendation.

Missing in the recommendation is anything related to Bonneville Power Administration's generation interconnection process, which has represented a substantial barrier to deployment that we all must be dedicated to resolving through innovative solutions and the pressure that the state and region can bring to bear.

Recommendation 8 – Accelerate Siting & Permitting of Transmission & Clean Energy

Comment: TNC supports this recommendation, as we strive to support efforts to accelerate the pace and scale of necessary transmission and clean energy, while both maintaining the protections for Tribal resources, natural lands, and community needs *AND* incentivizing more rapid decision-making processes for projects with lower conflict. In the nearest term, accelerating the pace as it relates to transmission capacity is of utmost importance for our state's decarbonized energy grid and to provide timely, firmer resources for data centers.

We concur with regional findings—including our own analyses—which show that fuel switching to electricity is essential to meeting Washington's climate targets. This likely necessitates at least doubling the supply of electricity resources, adding substantial transmission capacity, and deploying projects at a pace multiple times faster than we've deployed them in the recent past.

TNC believes there are current efficiencies to be gained in the review, permitting, and appeals processes, including some reform to the EFSEC process and structure and SEPA exemptions for reconductoring and rebuilding transmission with an agreed upon separate process for Traditional and Cultural resources.

We also believe creative paradigms that are substantially different from modus operandi may well be in order, and their growing examples in other jurisdictions that Washington should test out. Designating Clean Energy Acceleration Areas identified with Tribal consent, for instance. Or pre-application Traditional and Cultural Resource surveys led by Tribes in highest priority transmission corridors. Or a feed-in tariff to support win-win-win utility-scale agrivoltaics projects. Or a "fair share" threshold for solar development in each county's agricultural lands of long-term commercial significance tied to agricultural conservation easement purchases. Or enhancing Tribal ownership and investment structures.

We further believe that more effort is needed to place the avoidance of community, conservation, and Traditional and Cultural Resource conflicts on par for developers and utilities with finding willing landowners and transmission proximity. That can be and should be better incentivized or required.

Linking these two ideas – incentivizing or requiring more consideration of conflict avoidance and pre-application engagement and avoidance of Tribal resources, and then driving faster decision-making timelines – is too logical and attractive an idea to avoid any longer.

Importantly, better sited projects with faster timelines translates to less litigation costs and delays and much less time for developers to hold financing without revenue. We need to see that this is directly related to the costs utilities will then pass through to ratepayers for these resources. In a world where federal tax incentives are not available for now, protecting ratepayers through faster, less contentious review and decision-making is important.

To help with all of these concepts, TNC also expresses our strong support for Yakama Nation and Columbia River Intertribal Fish Commission recommendation for a Comprehensive Energy

and Transmission Plan that would identify where these facilities could be developed with the least conflict and areas that should not be developed. As they note, for such an effort to be most effective, the state family would need to step into a formal partnership role.

Recommendation 9 – Accelerate Deployment of Emerging Technologies

Comment: TNC supports this recommendation and believes smart utility policy could help direct data center electricity needs towards clean, firm resources that are grid-connected, such that they can contribute resource adequacy and reliability while reducing the need for as much variable generating resources over time. We believe a direct access program for new large loads in Washington to allow customers to source their own power should be limited to renewable resources and non-emitting electricity generation as defined in RCW19.405.020.

Draft Recommendation #5 – Provide for geographic equity and new clean energy requirements within the data center sales and use tax exemption

Comment: This was considered but narrowly not adopted by the Work Group. The first bullet in that recommendation is to:

> *Expand eligibility to all counties and align the requirements for the rural and urban exemption into one statewide tax incentive. Currently, Thurston, Kitsap, Whatcom, Clark, Benton, and Spokane County cannot qualify*.

TNC is potentially amendable to legislative dialogue expanding and aligning the scope of the incentives, but we feel that expansion and alignment should be *contingent* upon linking incentives with rigorous and sufficient new clean energy requirements and/or investments and demand flexibility approaches and considering energy and water efficiency and demand flexibility minimum standards.

For the second bullet in that recommendation, related to requiring new clean energy capacity requirements to data center tax incentives, please see separately submitted joint statement that TNC supported with partners, which are also included below. Separately, TNC believes legislative action on this topic should consider the geographic location of a new clean energy Power Purchase Agreement (PPA) associated with a Washington tax incentive. There is an active discussion at the moment around geographic location and time-matching associated with Virtual Power Purchase Agreements (VPPA). Recommendation #5 had not clarified if a PPA for new clean energy capacity was intended to only be for grid-connected power capable of servicing load in Washington or if a VPPA for new clean power elsewhere could be acceptable. The legislature should also consider if a PPA anywhere in the Western Interconnect is equivalent to a PPA in a more limited footprint, such as BPA service territory or the Northern Grid footprint.

> ***Joint Statement on Recommendation #5, Bullet Two Regarding Clean Energy***
> *Zachariah Baker, NW Energy Coalition; Cameron Steinback, Front and Centered; Justin Allegro, The Nature Conservancy*

Our organizations feel strongly that data centers must be powered by clean energy. The State's data center tax incentives don't currently require use of clean energy. Bullet Two of unsuccessful Recommendation #5 recommended changing that:

> *"Add a requirement to the tax incentive related to new clean energy capacity. There would be a variety of pathways for compliance with this requirement, such as data centers bringing a percentage of their own clean power generation, having a power purchase agreement (PPA) for new clean power capacity, or making contributions to grid capacity or transmission. The incentive could be tiered, offering a longer or more generous incentive for meeting higher clean energy requirements."*

In addition, by requiring data centers to bring their own clean energy capacity, Bullet Two also aimed to address reliability and affordability concerns with the growth of data centers.

If data center tax incentives continue to be provided by the State, Bullet Two's recommendation could be an important improvement. The specific details of the recommendation would matter in fully assessing the recommendation (e.g., the percent of clean energy and by when as well as the extent of the tax incentive). In addition it is important to ensure the demand to supply clean energy to data centers does not circumvent tribal sovereignty and community priorities or outstrip grid improvements that should benefit all as the state strives to meet its clean energy goals. But the thrusts of the recommendation - requiring data centers use clean energy as well as bringing some or all of their own clean energy are important concepts that should be included in any regulatory and/or incentive structure around data centers in Washington moving forward.

Washington has strong climate and clean energy policies that already require clean energy. Washington's electricity is required to be 80 percent clean (and carbon neutral) by 2030 under the Clean Energy Transformation Act and zero carbon by 2045. As a result, all data centers in Washington will ultimately need to be fully powered by clean energy. The question is how quickly. And that question is key.

The sooner data centers are powered by clean energy, the more chance Washington will have to meet its climate and clean energy commitments. Data centers consume large amounts of power. If that power is not clean from the jump, it will be much harder to achieve the state's climate and clean energy commitments over the medium and long term.

In addition to using clean energy, the concept in the recommendation of data centers bringing some or all of their own clean energy capacity is important. Data centers bringing their own clean power can help alleviate grid constraints in the near and long-term and help ensure ratepayers are not paying the costs to serve data centers (although not a complete solve for either one, and more actions would be needed – some of which are included in the Workgroup recommendations).

Many companies building data centers already have ambitious voluntary clean energy goals. For example, Microsoft has a goal of being carbon negative by 2030. In setting that goal, Microsoft explained[1]:

> *"While the world will need to reach net zero, those of us who can afford to move faster and go further should do so."*

We couldn't agree more. Companies who are building data centers or procuring data center capacity can and should move faster and go further. Requirements and/or incentives like Bullet Two in unsuccessful Recommendation #5 are consistent with these efforts.

With data centers expected to grow at a rapid rate, and the fastest growth projected over the next couple of years, it is critical that the concepts above are addressed through regulation and/or legislation quickly.

[1] https://blogs.microsoft.com/blog/2020/01/16/microsoft-will-be-carbon-negative-by-2030/

Appendix B: Other Feedback

Of the slate of nine draft recommendations put before the Workgroup for consideration, Draft Recommendation #5 was the only recommendation that did not pass on a vote of 11-12. Several workgroup members provided comments on this Draft Recommendation, which we are including below.

Here is Draft Recommendation #5 as it appeared before the Workgroup:

5. **Provide for geographic equity and new clean energy requirements within the data center sales and use tax exemption.**
    - Modify the data center sales and use tax exemption to:
        - Expand eligibility to all counties and align the requirements for the rural and urban exemption into one statewide tax incentive. Currently, Thurston, Kitsap, Whatcom, Clark, Benton, and Spokane County cannot qualify.
        - Add a requirement to the tax incentive related to new clean energy capacity. There would be a variety of pathways for compliance with this requirement, such as data centers bringing a percentage of their own clean power generation, having a power purchase agreement (PPA) for new clean power capacity, or making contributions to grid capacity or transmission. The incentive could be tiered, offering a longer or more generous incentive for meeting higher clean energy requirements.

Several members expressed support for expanding the tax preference to all counties while expressing opposition to the new clean energy capacity requirement. Conversely, several members expressed support for adding a new clean energy requirement to the data center tax incentives while opposing any expansion of the data center tax preferences. At least one member expressed opposition to Recommendation #5 as they opposed expanding the tax preferences alone and felt there was insufficient detail with the new clean energy requirement proposal to support the recommendation.

Below are the comments received regarding Draft Recommendation 5:

Diane Butorac, Department of Ecology

Ecology supported the recommendation to tie clean energy development to tax incentives in Washington. Data centers could help move the clean energy transition forward in Washington through new renewable energy development and innovative solutions. There is value in ensuring existing clean energy policies are implemented effectively and in considering how to additionally incentivize renewable energy development. Data center developers could support the clean energy transition in multiple ways, such as bringing their own clean power generation, through a power purchase agreement for new clean power capacity or making contributions to improve grid capacity or transmission. Data centers have

contributed to developing clean energy as part of the grid or behind the meter, however, we are concerned with the multiple current proposals in Washington that only consider fossil fuel options and dependence on unproven technologies for the future.

Zachariah Baker, NW Energy Coalition
Cameron Steinback, Front and Centered
Justin Allegro, The Nature Conservancy

Our organizations feel strongly that data centers must be powered by clean energy. The State's data center tax incentives don't currently require use of clean energy. Bullet Two of unsuccessful Recommendation #5 recommended changing that:

> *"Add a requirement to the tax incentive related to new clean energy capacity. There would be a variety of pathways for compliance with this requirement, such as data centers bringing a percentage of their own clean power generation, having a power purchase agreement (PPA) for new clean power capacity, or making contributions to grid capacity or transmission. The incentive could be tiered, offering a longer or more generous incentive for meeting higher clean energy requirements."*

In addition, by requiring data centers to bring their own clean energy capacity, Bullet Two also aimed to address reliability and affordability concerns with the growth of data centers.

If data center tax incentives continue to be provided by the State, Bullet Two's recommendation could be an important improvement. The specific details of the recommendation would matter in fully assessing the recommendation (e.g., the percent of clean energy and by when as well as the extent of the tax incentive). In addition, it is important to ensure the demand to supply clean energy to data centers does not circumvent tribal sovereignty and community priorities or outstrip grid improvements that should benefit all as the state strives to meet its clean energy goals. But the thrusts of the recommendation - requiring data centers use clean energy as well as bringing some or all of their own clean energy are important concepts that should be included in any regulatory and/or incentive structure around data centers in Washington moving forward.

Washington has strong climate and clean energy policies that already require clean energy. Washington's electricity is required to be 80 percent clean (and carbon neutral) by 2030 under the Clean Energy Transformation Act and zero carbon by 2045. As a result, all data centers in Washington will

ultimately need to be fully powered by clean energy. The question is how quickly. And that question is key.

The sooner data centers are powered by clean energy, the more chance Washington will have to meet its climate and clean energy commitments. Data centers consume large amounts of power. If that power is not clean from the jump, it will be much harder to achieve the state's climate and clean energy commitments over the medium and long term.

In addition to using clean energy, the concept in the recommendation of data centers bringing some or all of their own clean energy capacity is important. Data centers bringing their own clean power can help alleviate grid constraints in the near and long-term and help ensure ratepayers are not paying the costs to serve data centers (although not a complete solve for either one, and more actions would be needed – some of which are included in the Workgroup recommendations).

Many companies building data centers already have ambitious voluntary clean energy goals. For example, Microsoft has a goal of being carbon negative by 2030. In setting that goal, Microsoft explained[20]:

> *"While the world will need to reach net zero, those of us who can afford to move faster and go further should do so."*

We couldn't agree more. Companies who are building data centers or procuring data center capacity can and should move faster and go further. Requirements and/or incentives like Bullet Two in unsuccessful Recommendation #5 are consistent with these efforts.

With data centers expected to grow at a rapid rate, and the fastest growth projected over the next couple of years, it is critical that the concepts above are addressed through regulation and/or legislation quickly.

Appendix C: Rosters of Subgroups

Tax Revenue and Economic Development Subgroup Members

- Beau Perschbacher, Commerce & Economic Development Policy Advisor, Office of the Governor
- David Duvall, Senior Tax Policy Coordinator, Department of Revenue (Chair, Tax Revenue & Economic Development Subgroup)
- Keith Swenson, Deputy Assistant Director, OEDC, Department of Commerce
- Zachariah Baker, Regional and State Policy Director, NW Energy Coalition
- Ryan Beebout, Vice President, Sabey Data Centers - West
- April Berg, Representative, 44th Legislative District
- Glenn Blackmon, Energy Policy Director, Department of Commerce
- Matt Boehnke, Senator, 8th Legislative District
- Andreas Bohman, UW Vice President for Information Technology and Chief Information Officer, University of Washington
- Cassie Bordelon, Executive Director, Climate Jobs Washington
- Dan Diorio, Senior Director, State Policy, Data Center Coalition
- Latisha Hill, Vice President of Community Affairs & Chief Customer Officer, Avista Corporation
- Bill Kehoe, Director & Washington State Chief Information Officer, Washington Technology Solutions
- Heather Kurtenbach, Executive Secretary, Washington State Building and Construction Trades Council
- Brant Mayo, Executive Director, Grant County Economic Development
- Megan Schrader, Director of State and Local Public Policy, Amazon Web Services
- Edward Sheets, Senior Adviser & Consultant on Regional Energy, Yakama Nation (Alternate)
- Sharon Shewmake, Senator, 42nd Legislative District
- Kate Valdez, Environmental Coordinator, Yakama Nation Fisheries
- Seth Worley, Director of Government Affairs, UA Local 598
- Alex Ybarra, Representative, Washington State House of Representatives

Energy & Resource Impacts Subgroup

- Kate Brouns, Climate & Energy Policy Advisor, Office of the Governor
- Glenn Blackmon, Energy Policy Director, Department of Commerce (Chair, Energy & Resource Impacts Subgroup)
- Justin Allegro, Policy Director, The Nature Conservancy
- Zachariah Baker, Regional and State Policy Director, NW Energy Coalition
- Ryan Beebout, Vice President, Sabey Data Centers - West
- April Berg, Representative, 44th Legislative District
- Matt Boehnke, Senator, 8th Legislative District
- Cassie Bordelon, Executive Director, Climate Jobs Washington
- Diane Butorac, Clean Energy Coordination Section Manager, Department of Ecology
- Dan Diorio, Senior Director, State Policy, Data Center Coalition
- Mendy Droke, Director, State and Regional Affairs, Pacific Northwest National Laboratory
- David Duvall, Senior Tax Policy Coordinator, Department of Revenue
- Matthew Hepner, Executive Director of the Certified Electrical Workers of Washington & Councilmember, IBEW & City of East Wenatchee Councilmember
- Latisha Hill, Vice President of Community Affairs & Chief Customer Officer, Avista Corporation
- Kirk Hudson, General Manager, Chelan Public Utility District
- Josh Jacobs, Clean Energy Strategy & Planning Vice President, Puget Sound Energy
- Bill Kehoe, Director & Washington State Chief Information Officer, Washington Technology Solutions
- Heather Kurtenbach, Executive Secretary, Washington State Building and Construction Trades Council
- Casey MacLean, Washington Policy Manager, Renewable Northwest
- Brant Mayo, Executive Director, Grant County Economic Development
- Matthew Fox, Senior Director of Government Affairs, Microsoft[21]
- Brian Rybarik, Chair, Washington Utilities and Transportation Commission
- Megan Schrader, Director of State and Local Public Policy, Amazon Web Services

- Edward Sheets, Senior Advisor & Consultant on Regional Energy, Yakama Nation (Alternate)
- Sharon Shewmake, Senator, 42nd Legislative District
- Cameron Steinback, Climate Justice Program Manager, Front and Centered
- Kate Valdez, Environmental Coordinator, Yakama Nation Fisheries
- Andy Wendell, Senior Power Manager of Large Power Solutions, Grant County Public Utility District
- Seth Worley, Director of Government Affairs, UA Local 598
- Alex Ybarra, Representative, Washington State House of Representatives

Appendix D: Report from Yakama Nation

Confederated Tribes and Bands
of the Yakama Nation

Established by the
Treaty of June 9, 1855

November 10, 2025

Governor Bob Ferguson
426 Sid Snyder Ave SW
Olympia, WA 98501

Dear Governor Ferguson

The Yakama Nation is providing findings and recommendations on date center development in the state of Washington. This report is based on our participation on your Data Center Workgroup established pursuant to Executive Order 25-05 to provide recommendations on these important issues.

We want to thank you for convening the workgroup. We also want to thank the state staff for their extraordinary efforts to facilitate a complex set of issues on a tight schedule.

The recommendations that secured a majority vote address maintaining the integrity of Washington's climate laws; strengthening ratepayer protections; incentives for load flexibility and energy efficiency; protecting community, tribal, and environmental resources; improving resource forecasting; enhancing transmission capacity; siting and permitting of transmission and clean energy generation; and accelerating existing and emerging technologies to provide clean energy.

While this was a significant accomplishment, the Workgroup recommendations are general and did not address several of our key concerns. The Yakama Nation was the only sovereign on the Workgroup. We are providing our own findings and recommendations to the State of Washington on issues that are essential to protect our resources and culture.

The Yakama Nation has proposed 36 recommendations that address conditions for new data centers and actions to: 1) protect salmon and other tribal resources; 2) meet the region's energy needs; 3) promote clean energy; 4) improve transmission and energy siting, 5) protect water supplies for salmon and municipal water systems; and 6) shield consumers from higher electricity costs. Without actions by the governor and legislature, the Yakama Nation's treaty-protected resources face grave risks. We look forward to working with you and the legislature on these important issues.

Sincerely,

Gerald Lewis

Gerald Lewis
Chair, Yakama Tribal Council

cc:

Post Office Box 151, Fort Road, Toppenish, WA 98948 (509) 865-5121

Cc:
Beau Perschbacher, Commerce & Economic Development Policy Advisor, Office of the Governor
Kate Brouns, Climate & Energy Policy Advisor, Office of the Governor
Brian Rybarik, Chair, Utilities and Transportation Commission
Bill Kehoe, Director and Washington State Chief information Officer, Washington Technology Solutions Glenn Blackmon, Energy Policy Director, Department of Commerce
Keith Swenson Deputy Assistant Director, OEDC, Department of Commerce
Diane Butorac, Clean Energy Coordination Section Manager, Department of Ecology David Duvall, Senior Tax Policy Coordinator, Department of Revenue
Andreas Bohman, UW Vice President for Information Technology and Chief information Officer

The Yakama Nation Data Center Findings and Recommendations to the Washington Governor and Legislature



A Report Based on Participation on the Washington Date Center Workgroup

November 10, 2025

Contents

Executive Summary 4
Key Issues 4
Summary of Recommendations 6
State Tax Incentives 7
Conclusions 7
Introduction 8
Data Center Impacts on Tribal Resources 8
Data Center Effects on the Columbia Basin Restoration Initiative 9
Electric Energy 10
Findings 10
Data Center Will Add to Electricity Loads 10
Data centers Will Add to Peak Loads. 11
Data Centers Will Reduce Electricity Reliability 12
Challenges for Meeting Future Electricity Needs 12
Data Center Energy Efficiency 14
Data Center Load Uncertainty 15
Recommendations 15
Transmission and Siting 17
Findings 17
Transmission Access 17
Need for Comprehensive Energy and Transmission Plan 17
Recommendations 17
Water Use 19
Findings 19
Direct Impacts 19
Indirect Impacts 20
Recommendations 20
Effects on Consumer Electric Costs 21
Findings 21
Increases to Consumer Utility Bills 21
Recommendations 22
Tax Incentives 23
Findings 23

Do Tax Incentives Affect Where Data Centers are Located? 23
Are Tax Incentives Needed to Make Data Centers Profitable? 24
How do Data Center Jobs and Economic Benefits Compare to Other Tax Incentives? 24
Recommendations 25
Attachment A: 2022 Energy Vision for the Columbia River Basin: Energy Efficiency and Development Recommendations 26
Summary 26
CRITFC Energy Vision Recommendations 27
Reduce Peak Loads 27
Increase Electricity Storage 27
Maximize Energy Efficiency 28
Harness Renewable Resources & Integrate/Synergize with Electricity Storage 28
Strategically Site Renewable Resources 29
Increase Resource Adequacy 29
Attachment B: Statutory References 30
Northwest Power Act Provisions 30
Washington Statutory Provisions on Rate Equality 31
Public-Owned Utilities 31
Investor-Owned Utilities 32
Oregon Statutory Provisions 33
Attachment C: Factors Affecting Decisions on Location and the Profitability of Data Centers 34
Factors When Planning to Build New Data Centers 34
Economic importance of tax incentives 35

Findings and Recommendations on Data Centers

Executive Summary

Key Issues

The development of more data centers in Washington will create winners and losers.

The winners will be the data and artificial intelligence companies that profit from the new facilities; local and state governments that receive higher tax revenues; and construction workers that build the data centers.

There are also likely to be losers. Other businesses and consumers face risks of power blackouts and higher electricity bills; and current salmon protections are suspended during these emergencies and more migrating salmon will be killed. Additional resources and transmission lines to serve the data centers will damage tribal resources, and efforts to rebuild salmon and steelhead populations will be harder to accomplish. Water supplies for fish and wildlife and municipal systems could be affected. There may be more methane-gas power plants built and more pressure to weaken Washington's clean energy laws to reduce greenhouse gases.

The Yakama Nation signed a treaty with the United States in 1855 and reserved the rights to the salmon and other resources that have sustained our people since time immemorial. Without actions by the governor and legislature, those treaty-protected resources face grave risks.

We commend Governor Ferguson and state staff for convening the Data Center Workgroup to provide recommendations to the governor and legislature on these important issues. Given the diverse composition of the workgroup, it was difficult to get a agreement on some of controversial issues that were addressed. For example, the Yakama Nation and data center companies often took different positions on issues. We know that many of these companies are committed to protecting the environment, and we look forward to finding common ground to protect our treaty-protected salmon and other tribal resources.

The recommendations that secured a majority vote address maintaining the integrity of Washington's climate laws; strengthening ratepayer protections; incentives for load flexibility and energy efficiency; protecting community, tribal, and environmental resources; improving resource forecasting; enhancing transmission capacity; siting and permitting of transmission and clean energy generation; and accelerating existing and emerging technologies to provide clean energy.

While this was a significant accomplishment, the Workgroup recommendations are general and did not address a key concern regarding ensuring the reliability of the electric power system. The Yakama Nation was the only sovereign on the Workgroup. We are providing our own findings and recommendations to the State of Washington on issues that are essential to protect the Yakama Nation's resources and culture. We have summarized the key issues and recommendations in this executive summary and provided more details in the report.

Electric energy supply and reliability: The Pacific Northwest is facing major increases in electricity growth to serve new data centers and meet the decarbonization goals to reduce greenhouse gas emissions. Data centers could require the addition of new electricity equal to two to four cities the size of Seattle by 2029. If these data centers use conventional cooling, they could increase peak loads by 3,400 to 6,000 megawatts over the next five years. It is not realistic to assume that the region can add this much power, and a large electricity deficit is projected nationwide so market power may not be available, reliable, or affordable.

The Northwest Power and Conservation Council's most recent Electricity Adequacy Report says that the risk of annual blackouts increases from 5 percent to more than 13 percent if the region experiences the growth in data centers that utilities and the data center industry are projecting.

More migrating salmon will be killed: during these power emergencies, salmon protections, which include spilling the migrating fish over the dams, are suspended and salmon must go through the turbines. Higher loads will also put more pressure to ramp up the output from hydroelectric dams; these large fluctuations in river flows kill migrating salmon as they are delayed in the reservoirs and eaten by warm-water predators like Walleye.

Increased electricity costs: building the new resources and transmission to serve data centers will cost billions of dollars. Power developed to serve data centers over the next few years will likely utilize the most developable sites and the lowest-cost transmission upgrades. This could increase the costs for the remaining resources and transmission to meet other needs. Data centers may also be willing to pay a premium for power; this could increase the costs of market power and other new resources. These added costs could increase consumer utility bills without changes to ensure that the data centers pay all the additional costs they cause.

More pressure to weaken Washington's clean energy laws: it will be challenging to meet the near-term energy demands of data centers with renewable energy, energy efficiency, and storage. This will create more pressure to run existing coal-fired power plants and add additional methane gas-fired power plants. The Washington Department of Ecology has received applications to supply data centers with fossil-fueled plants.

Barriers to implementing the Columbia Basin Restoration Initiative: the CBRI was adopted in 2023 by the Yakama Nation, the State of Washington, and four other sovereign governments[1]. It provides a framework for a durable long-term strategy that restores salmon and other native fish populations to healthy and abundant levels, ensures a clean energy future, supports local and

[1] The CBRI was adopted by the Yakama Nation, Confederated Tribes of the Umatilla Reservation, Confederated Tribes of the Warm Springs Reservation, Nez Perce Tribe, State of Oregon, and State of Washington.

regional economic resilience, restores ecosystem functions and honors the longstanding commitments to Tribal Nations. These objectives will be more difficult to achieve without coordinated efforts by state and tribal governments to address the challenges posed by data centers.

Damage to treaty-protected resources: Meeting the data center loads risks additional harm to the tribal treaty-protected salmon and steelhead that are especially important to the tribal people that have been sustained by these resources since time immemorial. Additional resources and transmission could damage other tribal resources such as First Foods and cultural sites. The load growth also threatens the reliability of the Northwest power system, the implementation of the Columbia Basin Restoration Initiative, and additional costs for tribal and other consumers.

The development of hydroelectric dams, fossil-fuel generators, and transmission lines during the last 100 years have damaged tribal treaty-protected resources, including the loss of over 80% of the salmon and steelhead runs. It is critical that the next phase of regional energy development protects the tribes' treaty resources and rebuilds salmon and steelhead populations. Our recommendations highlight the importance of requiring consultation with tribes on energy and transmission siting.

Effects on water supplies: data center water use poses significant localized water quantity and quality impacts that could affect fish and wildlife and municipal water supplies. Water should not be allocated to data centers without analyzing the impacts to watershed conditions, including stream flows for fish, temperature, and pollution.

Summary of Recommendations

To address these challenges, we are recommending actions by the governor and legislator. A summary is provided here and there are more details in the report.

- Ensure that there are adequate electricity supplies before data centers begin operation. Data center operators and utilities need to demonstrate that there is no degradation in grid reliability or impacts on salmon protection measures.
- Ensure that the resources built for data center meet the state clean energy laws and schedules for reducing greenhouse gases.
- Protect water quality and quantity for fish and wildlife and other existing water users.
- Develop energy efficiency standards to reduce data center energy and peak loads.
- Develop programs to manage data center loads, including storage, on-site resources, and demand management.
- Work with the state of Oregon and the region's tribes to develop a comprehensive plan for locating new electricity resources and transmission facilities while protecting tribal resources.
- Ensure that laws and regulations are in place to require data centers to pay their full costs and protect other consumers from stranded costs.

We also identify additional studies and reporting requirements that will help the state of Washington make future changes as new information on the effects of data centers is available.

We are aware that several tribes, including the Yakama Nation, are evaluating the feasibility, costs, and benefits of data centers on tribal lands. We believe the conditions in this report are essential for protecting tribal resources.

State Tax Incentives

A major focus of the workgroup was whether the current tax incentives should continue, be expanded, or be conditioned on other policy objectives. The Workgroup did not have majority support for any of these actions.

The Yakama Nation has raised significant questions about whether the state tax incentives for data centers are in the public interest and whether they should be continued. We provided information that questions the need for the incentive because they are not a major factor in selecting the location of new facilities, and the data centers are very profitable. We sought independent analysis on the permanent jobs that are created and how the tax incentives per job compare to incentives for other industries. We also requested analysis of the impacts on electricity costs, Washington's clean energy goals, and water supplies. Unfortunately, state staff did not have the resources to address these important questions.

We do know that without the conditions summarized above, these incentives are clearly not in the interest of protecting our resources or tribal members. Until we receive credible information that addresses the issues we have raised, the Yakama Nation opposes the continuation of the tax incentives because we have not seen independent information that they are needed and in the public interest. Continuation of tax incentives would subsidize actions that will damage tribal resources. Any continuation of the tax incentives must be conditioned on data centers meeting the conditions in this report, including protections for: 1) the reliability of the electricity system, 2) salmon and other tribal resources, 3) Washington's clean energy laws, 4) water quality and quantity, and 5) consumers.

The Seattle Times recently reported that Washington has spent $1 billion on tax incentives for technology companies, but there is no way to determine the benefits. If the legislature continues data center tax incentives, it should set clear goals and objectives and direct state agencies to collect and analyze the information needed and regularly review the incentives to ensure they achieve those goals.

Conclusions

The Yakama Nation has proposed 36 recommendations that address conditions for new data centers and actions to: 1) protect salmon and other tribal resources; 2) meet the region's energy needs; 3) promote clean energy; 4) improve transmission and energy siting, 5) protect water supplies for salmon and municipal water systems; and 6) shield consumers from higher electricity costs. We look forward to working with the governor and legislature on these important issues.

Yakama Nation Findings and Recommendations

Introduction

The Pacific Northwest is facing major increases in electricity demand from data centers that may exceed the electricity supplies that are available. These new loads will be in addition to other electricity growth as the Northwest increases electrification to meet state laws to limit greenhouse gas emissions. Meeting these new data center loads increases the risk of additional harm to the tribal treaty-protected fisheries, including salmon, steelhead, and Pacific lamprey. These fish resources are especially important to the tribal people that have been sustained by these resources since time immemorial. The additional resources and transmission lines needed to serve these loads will also damage tribal resources that are essential for First Foods and the protection of our cultural heritage.

These higher loads could also make it more difficult to implement the Columbia Basin Restoration Initiative that was adopted in 2023 by the Yakama Nation, the Confederated Tribes of the Umatilla Reservation, the Confederated Tribes of the Warm Springs Reservation, the Nez Perce Tribe, the State of Oregon, and the State of Washington.

This document provides findings and recommendations by the Yakama Nation to the governor and legislature. They are based on the Columbia Basin Restoration Initiative, analysis by the Yakama Nation, results from a study by PAE Engineering on Energy and Water Use Impacts of Building System Design for Data Centers (https://critfc.org/documents/energy-water-use-impacts-of-building-system-design-for-data-centers/), and the Columbia River Inter-Tribal Fish Commission Energy Vision for the Columbia River Basin (www.critfc.org/energy-vision).

Data Center Impacts on Tribal Resources

In 1855, the United States signed treaties with four Columbia River basin tribes: the Yakama Nation, the Nez Perce Tribe, the Confederated Tribes of the Umatilla Indian Reservation and the Confederated Tribes of Warm Springs Reservation of Oregon[2]. In those treaties, the four tribes reserved their rights to tribal resources, including the salmon that are critical to tribal communities. Federal courts have consistently upheld the obligations to honor the treaties. The scale of fish losses since treaty signing is staggering: the Northwest Power and Conservation Council estimates that 10 to 16 million salmon and steelhead returned annually to the Columbia Basin when the treaties were signed[3], while current annual runs are approximately 2 million. The hydroelectric system alone is responsible for 5 to 11 million the annual fish losses[4].

Tribes have borne the brunt of energy development throughout the basin. Dam construction decimated salmon and steelhead runs and severely impacted other treaty fisheries such as lamprey and sturgeon. The salmon losses have damaged tribal economies and culture. These communities continue to experience higher unemployment and worse health outcomes than non-

[2] The Columbia River Inter-Tribal Fish Commission (CRITFC) was created to help protect these rights and serves as a technical support agency for these Treaty Tribes.
[3] Northwest Power and Conservation Council, *1987 Columbia River Fish and Wildlife Program*.
[4] Ibid.

tribal communities. Additional data center electricity loads threaten to exacerbate hydropower's existing detrimental impacts on anadromous fish species and other tribal fishery resources. Dam passage kills salmon and steelhead, while daily reservoir fluctuations slow salmon migration and increase exposure to high water temperatures and predators. These impacts affect not only salmon and steelhead but also sturgeon, and other species critical to tribal communities.

State and tribal anadromous fish managers have developed detailed measures to increase spills at the dams and increase travel time through the reservoirs that must be part of any future energy development.

Data centers impacts need to be analyzed through federal and state environmental justice principles that require addressing energy development impacts on overburdened communities, including tribal communities. It is important that the next phase of regional energy and grid development both protect the tribes' treaty resources and actively works to rebuild the fish populations that remain vital to tribal communities. This requires comprehensive planning that considers not just the data centers themselves, but the entire energy and transmission infrastructure needed to serve them.

Data Center Effects on the Columbia Basin Restoration Initiative

The CBRI provides a framework for a durable long-term strategy that restores salmon and other native fish populations to healthy and abundant levels, ensures a clean energy future, supports local and regional economic resilience, restores ecosystem functions and honors the longstanding commitments to Tribal Nations. Those objectives include:

1. ***Interim operation to improve the survival of migrating salmon***. High date center loads would reduce the reliability of the power system and increase the chance that fish operations will be interrupted.

2. ***Enhanced fish protection operations***. Higher loads will make it more difficult to implement those improvements.

3. ***Improve salmon and steelhead habitat***. The energy resources and transmission needed to serve data centers will affect land and water resources.

4. ***Meet Oregon and Washington greenhouse gas objectives***. The CBRI calls for meeting decarbonization goals, deliver “affordable and clean power”, and resiliency and adaptability to climate change. Any reductions in electricity adequacy will increase pressure to operate existing coal and methane-fired power plants.

5. ***Ensure continuity of services from the Lower Snake River dams***. projected electricity shortages could add to the time it would take to replace the energy services of these dams. Current output from the four dams is about 700 average megawatts; data center load growth is projected to range between 2,400 to 4,000 average megawatts by 2029.

6. ***Support communities and economic sectors***. Electricity shortages, brownouts, or blackouts and higher electricity costs would damage communities and other businesses.

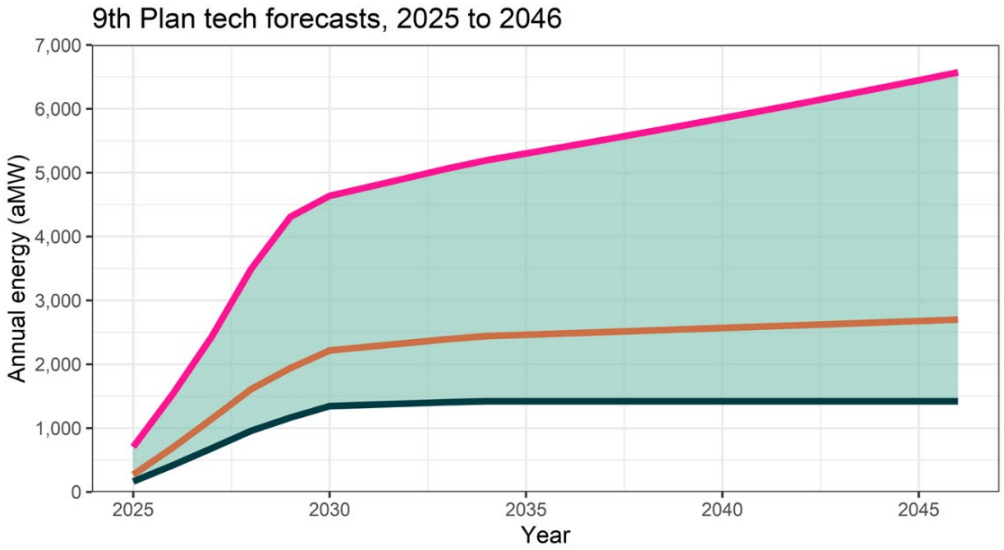
The Yakama Nation has proposed detailed findings and recommendations to the governor and legislature. The 36 recommendations address conditions for new data centers and actions to 1) meet the region's energy needs; 2) protect salmon and other tribal resources; 3) improve transmission and energy siting, 4) protect water supplies for salmon and municipal water systems; and 5) shield consumers from higher electricity costs. We look forward to working with the governor and legislature on these important issues.

Electric Energy

Findings

Data Center Will Add to Electricity Loads

The data center energy needs are likely to be significant. The Northwest Power and Conservation Council recently updated its electricity load estimates for data centers and chip fabrication[5]. It shows that if recent trends continue (including recently announced projects), these projects could increase the region's electricity demand by about 2,400 average megawatts by 2029. The Council also developed a high growth scenario (based on utility and BPA projections) that shows demand could increase by about 4,000 average megawatts by 2029 and 6,500 by 2046.



The **purple** high forecast through 2030 reflects utility and BPA growth expectations; the **brown** mid forecast is a continuation of recent trends; the **green** low forecast through 2030 has a slowing of recent trends. Post 2030 growth is at a fixed rate depending on the forecast.

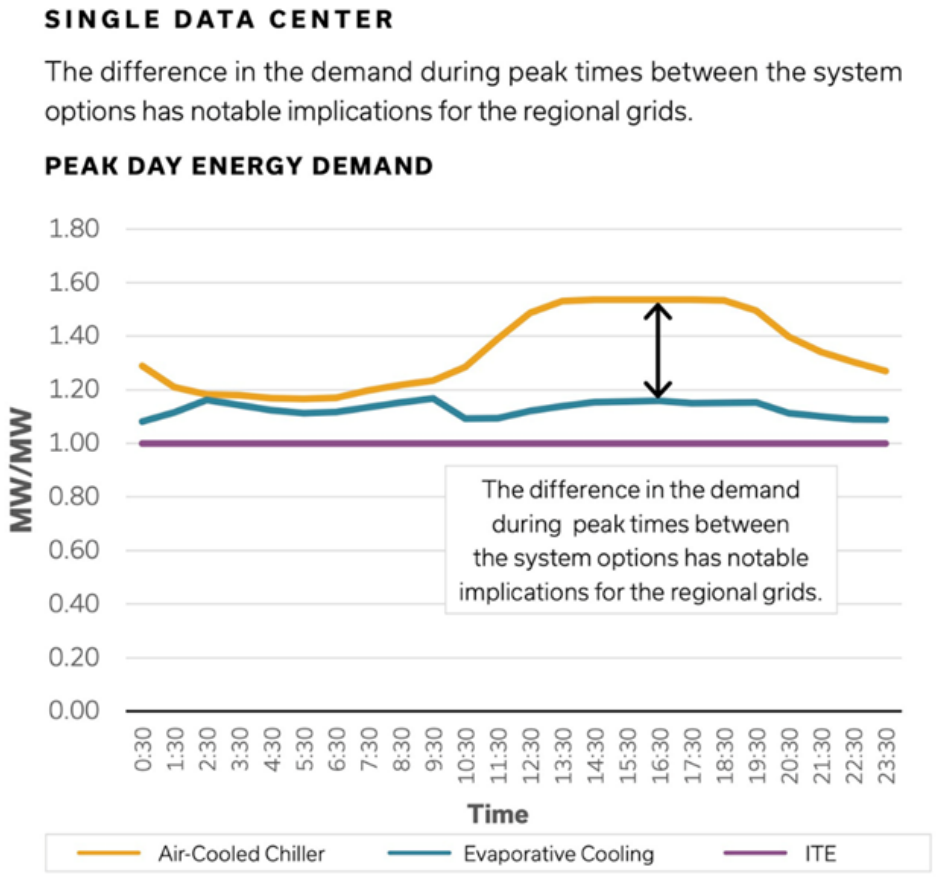
For comparison, at the medium estimate, the projected electricity use would be equivalent to adding the power used by two cities the size of Seattle during the next four years. At the high end of the range, the electricity use by 2029 would be similar to adding about four cities the size of Seattle.

[5] Northwest Power and Conservation Council, May 16, 2025.

Data centers Will Add to Peak Loads.

The PAE Study[6] identified significant peak load increases associated with data centers using conventional air-cooling systems (see below and on page 10 of the report for more details). This will be a significant challenge for the energy system. Meeting peak loads will be more expensive and stress the power system.

The chart below shows the load profile for a single data center under two technologies. The blue line uses evaporative cooling and has a relatively constant energy use with cooling loads adding about 10 to 20 percent to the computer processing load. The gold line shows the best-available air-cooling systems. These cooling loads also add about 20 percent during parts of the day, but when temperatures increase, the addition energy use for cooling adds a peak of about 55 percent above the processer loads. If this load shape is typical for 1,000 megawatts of data center load, the peak load would be about 1,550 megawatts.



Without electricity efficiency standards to reduce peak loads and clear price signals about the cost of electricity during different times of the day, the data center peak loads will adversely affect the electric power system and migrating salmon.

In the past, peak loads were served by ramping up the output from hydroelectric dams. Today, the use of dams to meet peak loads and to integrate renewable intermittent energy has

[6] https://critfc.org/documents/energy-water-use-impacts-of-building-system-design-for-data-centers/

dramatically increased the flow fluctuations in reservoirs and between dams, resulting in increased mortality for salmon migrating through the Columbia and Snake rivers. The Washington, Oregon, and tribal fish managers[7] have recommended changes in dam operations to increase water spilled over the dams to help juvenile salmon avoid being swept into the power turbines at the dams and lower reservoir elevation levels to help speed the journey of juvenile fish through slow moving reservoirs on their way to the ocean. These changes would also limit the daily river fluctuations.

Data Centers Will Reduce Electricity Reliability

Resource availability and adequacy are major issues. Meeting the data center energy needs, along with electrification of other sectors of the economy, will require significant growth in energy efficiency programs, renewable resources, demand management, and energy storage.

It is not realistic to assume that the region can add 2,000 to 4,000 average megawatts, 3,000 to 6,000 megawatts of peak, and the associated transmission system upgrades in the next five years as needed to meet the projected data center loads. Adding these large data center loads will affect the reliability of the electricity system and likely force a serving utility to increase its reliance on purchases of market power – an unreliable and price volatile resource. Nationwide, the projected electricity deficit to serve data center loads is 45,000 megawatts through 2028[8]. Market resources of this magnitude, if even available, will likely be very expensive.

The Northwest Power and Conservation Council (NPCC) updated its reliability analysis in August 2024[9]. It concluded "should data center load growth accelerate and exceed current trends to match high-end trajectories of utility projections by 2029, the resource strategy will also be insufficient to maintain adequacy as the Higher Data Center scenario violated all adequacy metrics… Shortfall risk is heightened in both winter and summer; Significant increases in duration, peak, and especially energy metrics in major winter shortfalls" (page 26). The Council seta a limit of 5 percent annual loss-of-load probability (LOLP) metric to measure resource adequacy. Under the high data center scenario, the LOLP is 13.3%[10].

An imbalance between a system's loads and its electric resources increases the frequency and duration of outages, such as brownouts and blackouts that can hurt all consumers. When such power emergencies occur, salmon protections are shut off. That means that dam operators stop spilling water over the dams for migrating salmon and the fish have to pass through the powerhouse turbines.

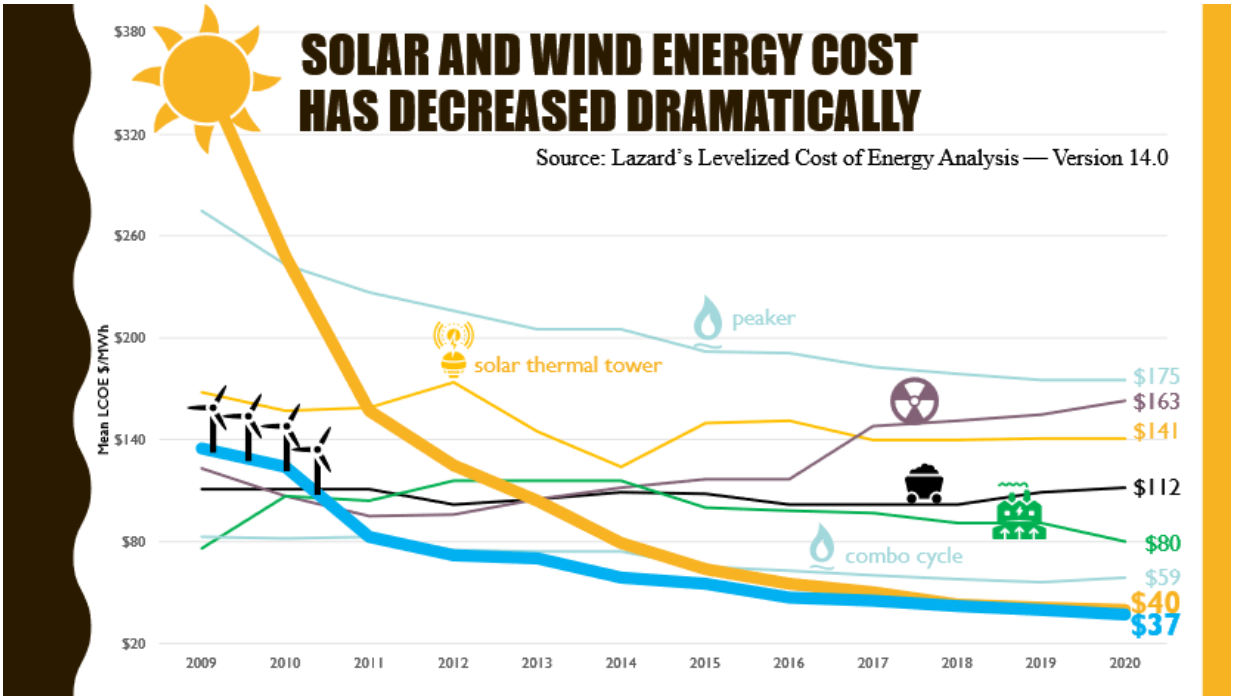
Challenges for Meeting Future Electricity Needs

Adding 2,000 to 4,000 megawatts of new electric energy resources and the transmission to deliver the power in the next four or five years would be unprecedented. This level of development would also adversely affect tribal resources throughout the state. This section summarizes the costs of alternative resources and challenges in accelerating their development.

---

[7] Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe, Confederated Tribes of the Umatilla Indian Reservation, and Confederated Tribes of the Warm Springs Reservation of Oregon.
[8] Morgan Stanley Research, Global Data Center Capacity Growth to Increase 6x, page 44, July 15, 2025
[9] https://www.nwcouncil.org/reports/2024-4/
[10] https://www.nwcouncil.org/reports/2024-4/, page 28. See more details in Appendix.

Costs: To develop adequate resources and ensure the reliability of the power system, the 2022 Columbia River Inter-Tribal Fish Commission's Energy Vision for the Columbia Basin energy resources recommendations were based on an analysis of alternative energy costs using data from the Lazard investment bank. Lazard publishes a yearly summary of generation costs. Their summary uses actual transaction data – not estimates – and is commonly viewed as authoritative. The chart below shows costs per megawatt hour ($/MWh). Solar and wind projects were the lowest costs at $37 and $40 per megawatt hour; combined cycle plants fueled by methane gas cost $59 per megawatt hour; geothermal power cost $80 per megawatt; all the other alternatives cost more than $110 per megawatt. The Lazard data shows the solar and wind energy costs have decreased dramatically and are lower than other generating alternatives. Energy efficiency programs were not reported by Lazard, but have lower costs than generating resources, provide energy and peak reductions, and do not require transmission or distribution upgrades.



There are significant challenges for each of these technologies:

Energy efficiency: There is potential to increase these programs, but it would require more funding by BPA and individual utilities.

Renewable resources: The recently enacted federal reconciliation law phased out the production tax credits that have been driving the recent increase in renewable resources. The loss of these credits is likely to slow wind and solar power development and increase costs. The current administration is also imposing barriers to solar and wind projects.

Demand management: The region has limited experience with these programs and would need to increase staffing and funding.

Storage: The costs of storage have declined significantly. California has added 7,000 megawatts of storage in the last few years. Storage will require significant investment and integration in grid planning.

Conventional methane gas and coal-fired power plants: These plants are more expensive and generate greenhouses gases and other emissions. Lead times for delivery of new gas turbines range from three[11] to seven years[12]. State laws in Oregon and Washington set firm limits to reduce and ultimately eliminate these resources.

Small modular nuclear reactors: The industry has been promising this technology for more than 40 years. There are no SMRs operating in the United States. Only China and Russia have successfully built operational SMRs. There are potential projects being discussed in the United States, but it is unlikely that this technology will be commercially available anytime soon. SMR plants will be more expensive than the sources described above.

Data Center Energy Efficiency

Energy efficiency could reduce data center electricity demand. The amount of electricity needed will depend on the efficiency of the cooling systems. There is significant potential to reduce energy and peak load electricity use; this could reduce the range of energy needs. The PAE study on the potential for efficiency improvements found:

- There is a big difference between the ASHRAE national standard for data center and the best practice technologies for building cooling systems.
    - The potential savings are equivalent to 2 million to 4 million megawatt hours.
    - These savings are only from building system improvements without any reduction in data center processor quantity.

- The study identified a potential for 1,000 megawatts reduction in peak energy savings from best-practices cooling systems:
    - Evaporative cooling systems are 28% more efficient than current standards.
    - Best-practices air-cooled savings are 4% more efficient.
    - Air-cooled compressors have large peak loads, especially during summer afternoons and evenings.
    - Peak loads are expensive to serve, stress the electricity system, and hurt migrating salmon.

- Implementing the energy efficiency and peak power reductions identified in the PAE data center report would provide some of the most significant energy savings available to the region.

Washington's law that provides tax incentives for data centers does not include any requirement that data centers incorporate these energy efficiency measures. Oregon similarly provides tax incentives without energy efficiency requirements. Oregon HB 3409 does impose energy

[11] Reuters: https://www.reuters.com/business/energy/rush-us-gas-plants-drives-up-costs-lead-times-2025-07-21/
[12] S&P Glogal: https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply

performance standards for commercial buildings, including data centers, but does not require compliance until 2028, at the earliest.

Data Center Load Uncertainty

There is a great deal of uncertainty about how much electricity data centers will use. There is potential duplication or speculation of data center projects. It is important to improve estimates in order to clarify which of the planned projects are viable.

There appeared to be utility industry support for setting "commercial readiness" standards to get in the energy service queue. This could significantly affect projections. For example, Grant County PUD discussed policy changes on their data center queue that resulted in a reduction in service requests from 3,000 to 2,300 megawatts—a 23 percent reduction.

Recommendations

1. The NPCC should incorporate the anadromous fish managers recommendations on the spill and reservoir operations at the dams into the Columbia Basin Fish and Wildlife Program. The NPCC would then incorporate those operations in the development of the next Pacific Northwest Conservation and Electric Power Plan.

2. The NPCC and federal agencies should adopt the provisions in the Columbia Basin Restoration Initiative adopted in 2023 by the Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Umatilla Reservation, the Confederated Tribes of the Warm Springs Reservation, the Nez Perce Tribe, the State of Oregon, and the State of Washington

3. To avoid a degradation in the reliability of the electricity system and avoid impacts on salmon and other tribal resources, data centers should demonstrate that they have sufficient reliable energy available before they begin operation. These new energy sources should be based on the recommendations in the Tribal Energy Vision for the Columbia Basin and the CBRI that are described in more detail below.

4. Utilities and regulatory agencies should ensure there are sufficient resources to meet the base and peak energy needs (energy and capacity) before data centers begin construction.

5. BPA and grid operators should assess the reliability risks associated with the growth in data center loads.

6. The Council, BPA, utilities, and state utility regulators and transmission organizations should incorporate the energy reliability recommendations in the CRITFC Energy Vision for the Columbia River Basin into their energy plans. A list of the relevant recommendations is provided is Attachment A.

7. The Council, BPA, utilities, and state utility regulators should incorporate the energy efficiency and development recommendations in the CRITFC Energy Vision for the Columbia River Basin into their energy plans. The recommendations are designed to ensure

that renewable resources in combination with increased storage, reductions in peak demand, and increased energy efficiency can provide clean, adequate, reliable, and affordable electricity, support the restoration of heathy, harvestable salmon populations, and prevent future damage to salmon and steelhead and other tribal resources caused by the electrical system. A list of the relevant recommendations is provided in Attachment A.

8. Data centers should be required to use the most energy efficient processing and cooling technologies commercially available at the time of construction to reduce their energy load and impact on the grid. If evaporative cooling is not feasible, the data center should mitigate energy and peak load impacts using storage or other technologies. The Washington State Energy Office should develop detailed efficiency standards based on the PAE Study recommendations:

    a. Develop a reach code for projects over a certain size that goes beyond the minimum requirements of ASHRAE 90.4 to ensure optimized systems for improved Power Usage Effectiveness (PUE)

    b. Creation and adoption of a Peak-PUE metric to encourage selection of systems with reduced peak demand impacts.

    c. Encouraging innovation in the data center industry for creative water solutions to reduce the overall water impact.

9. Any state tax incentives should be conditioned on achieving the data center energy efficiency actions in recommendation 8 and time-of-use electricity pricing.

10. BPA, federal dam operators, and utilities should avoid any impacts on anadromous species from data center loads.

11. To reduce the uncertainty of data center loads, the Washington State Energy Office should develop standards for commercial readiness to get into the queue for energy services.

12. The Washington State Energy Office should conduct a study at least every two years on the potential for on-site energy generation or storage, load management, and demand response by data centers, including any program or policy changes that may be needed to achieve the potential.

13. Data centers should report annual and monthly energy use, including peak demands, including metrics on efficiency and renewable energy use.

14. Data centers should conduct annual energy audits to identify opportunities for reducing energy consumption, improving efficiency, and minimizing peak loads.

Transmission and Siting

Findings

Transmission Access

Transmission access is constraining resource development. For example, Yakama Power is working to develop a utility-scale solar project over the canals of the Wapato Irrigation District and an energy storage system[13]. Yakama Power has not been able to secure commitments for BPA transmission access and BPA has said that Yakama Power would need to build a $130 million substation for the project. The Warm Springs Power & Water Enterprises in Oregon is also pursuing a large solar project and facing barriers to transmission access.

Need for Comprehensive Energy and Transmission Plan

The CRITFC Energy Vision called for a comprehensive energy siting program that would identify where these facilities could be developed with the least conflict and areas that should not be developed. Tribes are concerned that these facilities will damage tribal cultural, environmental, and fish and wildlife resources.

Any suggestion or recommendation to accelerate or streamline SEPA through categorical exemptions removes a Tribes ability to have meaningful engagement and consultation through the environmental and cultural review process. If categorical exemptions are going to be suggested or recommended, then language regarding engagement and consultation with Tribes needs to be strengthened to "Directed" or "Required". For example, language as recommended within the Interagency Clean Energy Siting Coordination Council offers SEPA categorical exemption incentives for utilities to complete upgrades, however, it recommends engagement with Tribes on such exemptions. As written, it engagement and consultation is discretionary, when it needs to be "REQUIRED". Furthermore, agencies should be required to consult in a manner that identifies and addresses the Tribe's concerns. This would not only ensure the required engagement with Tribes but would support the intent of recently passed Executive Order 25-10.

The energy and transmission needs of data centers will also affect local communities and grid reliability and these issues need to be addressed.

Recommendations

15. Recommendation 3.6 of the CRITFC Energy Vision says:

> CRITFC and its member tribes should work with state energy and siting agencies, federal agencies, WestTEC, the Northwest Power Pool, and others to develop a timely comprehensive plan for siting renewable resources and transmission lines that builds on efforts currently being developed in the states.

[13] https://aresnorthamerica.com/.

The comprehensive plan should identify where renewable resources should be developed, and where they should not. The plan should provide expeditious siting with clear and uniform standards across all political subdivisions that sites resources near loads and within the grid to relieve congestion, and that protects fish, wildlife, and other environmental values and tribal resources.

The section provides examples of where comprehensive siting has been done successfully.

16. Strategically locating some electricity generation closer to loads, in combination with reducing peak energy demands, will eliminate some of the planned costs and impacts associated with expanding the transmission and distribution system. Utilities should develop interconnection standards that allow for safe operation of local generators. Distributed generation can be deployed to eliminate the need for backup generation and transmission and distribution capacity.

17. Develop distributed generation resources, including fuel cells, net-metered small renewable resources, and small wind farms. Owners of net-metered small renewable resources, including solar photovoltaic applications, should be able to sell power back to the local utility at retail prices. Small wind farms of two to ten machines can be placed strategically within the grid and not necessarily where wind is the greatest, but where the combination of strategic placement and the wind resource yields the highest benefit to the electricity system. This benefit would show up as income to the wind developers and savings in transmission and distribution construction costs.

18. Developing renewable resources next to existing transmission is another siting strategy that could minimize the costs and impacts of adding new resources. For example, Montana wind is well positioned to serve westside load centers while minimizing impacts on river operations. In addition to having the highest capacity factors (40-50 percent), it generates primarily during the winter, so its generation pattern best fits PNW peak load shapes; and it can use over 1,000 megawatts of repurposed Colstrip transmission rather than needing to build new, much more expensive transmission to serve westside loads. Because of these characteristics, Montana should help meet PNW winter capacity needs while also lessening river operation and upland impacts.

19. Reconductoring existing lines should be a priority. This technology is likely to be less expensive and have fewer adverse impacts on land and water resources than new transmission lines.

20. The state should not support or permit transmission projects that directly impact tribal treaty-protected fishery resources and fish habitat. This includes avoiding new transmission infrastructure such as underwater cables that place additional burdens on fish resources already stressed by existing hydropower operations. Transmission planning must prioritize routing that avoids critical fish habitat, spawning areas, and migration corridors. When transmission projects are proposed that could affect treaty fisheries, they must undergo comprehensive environmental review that includes meaningful consultation with affected tribes and demonstrates no net loss to fish populations. Alternative transmission routes and

technologies should be evaluated to ensure that the infrastructure needed to serve data centers does not further compromise the salmon, steelhead, sturgeon, and lamprey populations that are central to tribal treaty rights. The cumulative impacts of transmission projects, combined with existing dam operations and new data center loads, must be assessed to prevent additional degradation of already imperiled fish runs.

21. State and federal environmental laws, and all laws that protect riparian areas, critical areas and historical and cultural areas are necessary statutes to follow and monitor environmental protection. In order for Tribal resources to be protected, these laws must stay in place and not exempt any permit reviews or regulation of activities related to the building out of data centers, data cables, or energy and transmission facilities to serve them. We strongly oppose categorical exclusions because they eliminate meaningful consultation with Tribes.

22. Tribes are the experts on natural resource restoration and protection and must be involved in data center permitting processes, serving as experts on data center impacts to natural resources and how impacts could be avoided. Therefore, it is essential to engage with tribes early and often to address potential impacts on tribal resources. Furthermore, engagement with tribes should be required and guided by Executive Order 25-10.

23. If data centers seek expedited interconnection, they should prepay for necessary grid infrastructure.

24. Data centers should develop community benefit programs to address local impacts.

Water Use

Findings

Direct Impacts

Data center water use could be a significant issue, especially in areas with low water supplies or salmon and steelhead listed under the Endangered Species Act. Data center water use poses significant localized impacts that could impact fisheries. Water withdrawal reduces availability for other uses including fish flows, while decreased water volumes reduce cooling capacity and increase heat loading in waterways. Water quality issues arise from discharge, and reliance on municipal systems may not adequately address these concerns. Specific concerns include:

- Thermal Pollution: data centers often return heated water to municipal or natural systems, potentially stressing ecosystems. Higher risk in sensitive or low-flow waterways.
- Water availability: Water availability for data centers is limited by seasonal shortages and over-allocated watersheds, particularly during late summer when additional withdrawals could reduce instream flows below levels necessary for fish survival. Many locations cannot guarantee year-round water availability, and new withdrawals would compound existing stresses on treaty-protected fish populations.
- Chemical Contaminants: Cooling towers may involve biocides, anti-scaling agents, and corrosion inhibitors. Improper discharge can introduce these into receiving waters.

- Destination of Discharge: Could go into municipal wastewater system (possibly requiring pre-treatment) or directly into surface water bodies, depending on permits and infrastructure.
- Stormwater & Spill Risks: Data center sites can generate stormwater runoff and may handle fuels or chemicals (e.g., for generators), creating potential for site contamination. See The Dalles/Google data center.
- Regulations: NPDES in some jurisdictions.

Local water resources are being stressed and this increase given on-site water usage is expected to increase with hyperscale data centers. Climate change and the decline in water, all communities will ultimately have less water to compete over.

Indirect Impacts

Data centers also have indirect effects on water-- 75% of the water footprint of data centers is offsite associated with fossil-fired electricity generation. The CRITFC study analyzed the water use of data centers and alternatives energy sources to serve them. For more information, please see pages 12 and 13 of the PAE study.

Evaporative cooling systems use more water than air-cooled systems. The total projected use of evaporative cooling is a small percentage of total water use; however, the local effects on salmon and steelhead need to be avoided.

Recommendations

25. No water resources should be allocated to data centers, unless it can be demonstrated that such use would not affect watershed conditions, including stream flows for anadromous species, temperature, and pollution.

26. No water resources should be allocated to data centers, unless it can be demonstrated that such use would not affect local municipal water sources.

27. Water allocation decisions for data centers must account for existing over-allocation, climate change projections showing reduced snowpack and earlier runoff, and the cumulative impact of all water uses on treaty-protected fishery resources.

28. Data centers should report water use to the Washington State Department of Ecology. The reporting should include daily quantities (total and peak uses), any effluents that are discharged outside the data center, any impacts on existing water systems (for example, data center discharges that cause a municipal water system to exceed its capacity resulting in untreated water entering streams or rivers, or adverse impacts on ground water).

Effects on Consumer Electric Costs

Findings

Increases to Consumer Utility Bills

Cost protection for consumers is a significant issue. This is especially important in tribal communities where average incomes are below other communities. Building new energy and transmission facilities will cost billions of dollars and could directly increase consumer electricity costs. There are also potential indirect impacts. If the data centers use the most developable new generation sites and significant portions of the lowest-cost transmission upgrades, it would increase costs to other consumers even more. Some data centers may be willing to pay a premium for electricity[14]. This could also increase the cost of resources for other consumers.

Consumers and other industries may also pay more under the clean-energy programs. For example, if utilities develop fossil-fueled resources to serve the data centers they would receive no-cost allowances under the Climate Commitment Act. This would reduce the revenue the state generates at auctions and could drive up prices of allowances for other industries. Data centers using fossil fuels as the main source of power would need to buy allowances and that could also increase the price of allowances. Utilities developing methane-gas powerplants would need to purchase offsets. An increase in fossil fuels could also add to the costs of natural gas.

Investor-Owned Utilities: The Washington Utilities and Transportation Commission and the Oregon Public Utility Commission regulate how a utility's costs are allocated to its customers. The utility's rate design captures the unique costs that a utility must incur to serve a particular class of customers or special customers in a class. Equitable and effective rate design will ensure that the utility's costs to serve a particular customer class (e.g. residential, commercial, industrial, or data centers) will be allocated to that class in rates. Given the size of data centers, a separate customer class will be needed.

The utility commissions also address stranded asset risks. If investments are made to serve a data center that does not get built or shuts down, there needs to be mechanisms in place to protect other rate payers from these costs and ensure that data centers pay the stranded costs of the energy and transmission facilities built to serve them.

The Oregon POWER Act (House Bill 3546), creates a new customer rate class for data centers and cryptocurrency within Oregon's investor-owned utilities, allowing the OPUC to ensure these large customers pay for their fair share of the energy infrastructure costs in Oregon. The act aims to prevent residential and small business customers from subsidizing these large energy consumers. The legislation also requires large energy users to sign a 10-year contract that commits them to pay a minimum amount for energy used as well as pay for adding new transmission.

Publicly Owned Utilities: Each public utility sets its own rates. Several of the Mid-Columbia

[14] Morgan Stanley Research, *The Overlooked Value of Power,* October 10, 2024, pages 2, 7, and 20.

utilities reported that they have served data centers from excess generation produced by the dams they own. As those supplies are fully committed, these utilities will need to add new resources to serve additional data center load. Other public utilities will also need to arrange for new resources or purchase electricity from BPA. Like the customers of investor-owned utilities, the rate payers of consumer-owned utilities should be protected from the capital and operational costs associated with acquiring these new resources.

Data centers served by BPA customers would be considered a "New Large Single Load[15]" as defined in Section 3(13) of the Northwest Power Act. As such, the "average system cost" for electric power sold by the Administrator cannot include the "cost of additional resources in an amount sufficient to serve any new large single load of the utility." See 5(c)(7)(A). That means loads over 10 megawatts will not have access to BPA's low-cost power and would be served from BPA's new resources pool.

To avoid rate impacts to other customers, all utilities will need to ensure that cost causers pay their costs.

Recommendations

29. State utility commissions and public utilities should ensure that the cost causer pays the cost of services provided and load growth due to data center development should be attributed to data centers when making rates to ensure equity and fairness to existing consumers.

30. The WUTC and public utilities should adopt additional tools to address data centers, for example:

    a. A separate customer class for very large new loads or a separate data center tariff to ensure proper cost allocation.

    b. Mechanisms to address stranded costs if a data center leaves the service territory or goes out of business.

    c. Mechanisms to address any unused capacity that was built to meet a data center's estimated peak capacity requirement but never fully used by the data center due to customer loss, a slower business cycle, or just slower than expected growth.

31. The WUTC should evaluate investor-owned utility plans to serve data centers to ensure that they fully address the state climate and energy goals and policies. Consumer-owned utilities should conduct similar evaluations.

32. Utilities should regularly conduct a cost-of-service study to ensure that rates are designed to only recover the costs caused by each customer class.

[15] 3(13). "New large single load" means any load associated with a new facility, an existing facility, or an expansion of an existing facility– which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period.

33. Data centers should be required to enter into long-term, binding contracts to cover generation, transmission, and distribution costs, with provisions for exit fees and insurance bonds to mitigate the financial risks if they cease operations or underutilize investments that were made to serve them.

34. To address the potential that data centers could increase costs for other consumers by utilizing the most developable or lowest-cost resources and transmission expansions, the Washington State Energy Office should prepare an analysis of these issues and prepare recommendations to address them.

Tax Incentives

Findings

A major focus of the workgroup was on the tax incentives. As discussed below, the Yakama Nation had concerns about continuing the tax incentives. The Yakama Nation, NGOs, and state agencies proposed new conditions that could address some of the impacts of new data centers. The data center industry and labor supported expanding the program to the entire state but had concerns about additional conditions. After extensive discussion, the Workgroup did not have majority support for any of these actions.

According to Department of Revenue's Annual Tax Preference Performance Report data, the tax incentives to data centers and data center tenants were $584 million over the last decade (2012-2023). In 2023, the most recent data available, tax exemptions totaled over $118 million. If the state experiences significant data center growth, the impact of the tax incentives will increase. The Yakama Nation has raised a number of questions about the costs and benefits of the tax incentives in the Data Center Workgroup.

The Seattle Times reported recently that Washington has spent $1 billion on tax incentives to encourage high technology companies to locate in this state, but there is no way to determine the benefits.[16] The current tax incentives for data centers will soon exceed $1 billion. The current program has some requirements for employment and other goals, but the state cannot currently report on whether those goals are being achieved.

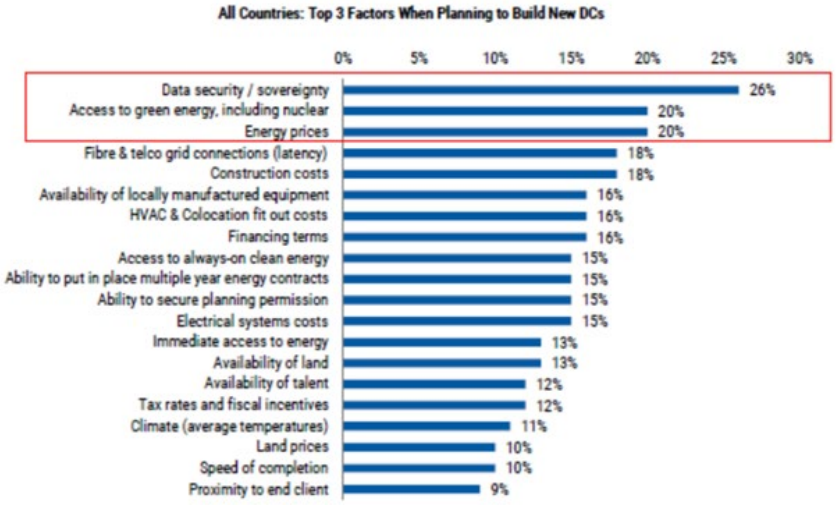
Do Tax Incentives Affect Where Data Centers are Located?

A key question raised by the Yakama Nation is how important are the tax incentives to the decisions on where they are located? Based on the independent research we have found data security, energy prices, access to energy, and speed to completion are the most important factors.

The Exhibit below is based on two surveys that were conducted for Morgan Stanley Research by AlphaWise in March 2025. The first was based on 239 interviews with senior procurement and sourcing decision makers for data center operators. The second survey interviewed 234 senior sources decision makers at data center builders and suppliers. Based on the survey, tax rates and fiscal incentives were 16th on the list of factors when planning to build data centers[17].

[16] *WA spent a billion in tax breaks to help tech dominate. Was it worth it?* Seattle Times, November 2, 2025.
[17] *Global Data Center Capacity Growth to Increase 6x*, Morgan Stanley Research, page 7.

Exhibit 8: Top 3 factors when planning on building DCs (US, UK, Italy, Spain and Norway)



Please see attachment C for more details.

Are Tax Incentives Needed to Make Data Centers Profitable?

The Yakama Nation representatives also raised questions about economic importance of tax incentives for the economics of data centers. An analysis by TeraWulf showed potential illustrative business models for financing data centers. The summary appears to show that data centers could be very profitable. The margins (profits) range from 65 to 90 percent and the Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) range from valuation of 7 to 20 times EBITDA. This information indicates that data centers are very profitable. The companies building data centers have some of the highest valuations in the world (see attachment C for more details).

How do Data Center Jobs and Economic Benefits Compare to Other Tax Incentives?

The Yakama Nation has sought information on the number and type of permanent jobs provided by data centers. Staff at the Department of Revenue have indicated that this information is not available and a change in state law would be needed to provide the data.

The staff cited RCW 82.32.330. A Yakama Nation consultant reviewed of the provision and assumed that the number of jobs created by data centers are part of their tax return or in the report to the Department of Revenue as required by the tax incentives. The consultant raised a question about Section (3) which says"

> (3) This section does not prohibit the department of revenue from:"
>
> (d) Publishing statistics so classified as to prevent the identification of particular returns or reports or items thereof;…

We sought clarification on whether DOR could provide data on the aggregate total number of

jobs created under the tax incentives for data centers and any other industries that receive tax incentives. The aggerate data would be very useful in addressing the effectiveness of the tax incentives for data centers compared to those offered to other industries. We also asked for clarification of the specific legal barrier and what the legislature would need to do to allow reporting of aggregate jobs data. As of the deadline for this report, we have not received a response to these questions.

A similar question exists for reporting aggregate information on the taxes paid by data centers and the economic contributions to the economy from the data centers and how they compare to other industries receiving tax incentives. The Data Center Coalition provided a report to the workgroup on the industry's jobs and economic impacts but no comparison to other industries. The state staff did not have the resources for an independent evaluation of the Data Center Coalition report.

Recommendations

35. Until we receive credible information that addresses the issues we have raised, the Yakama Nation opposes the continuation of the tax incentives because we have not seen independent information that they are needed and in the public interest. Continuation of tax incentives would subsidize actions that will damage tribal resources. Any continuation of the tax incentives must be conditioned on data centers meeting the conditions in this report, including protections for: 1) the reliability of the electricity system, 2) salmon and other tribal resources, 3) water quality and quantity, and 4) consumers.

If the Washington Legislature continues the data center tax incentives:

36. The legislature should set clear goals and objectives for what the tax incentives are intended to achieve and direct state agencies to collect and analyze the information needed to ensure the programs achieve those goals. The legislature should regularly review this information and adjust the program. Specific actions should include:

    a. The governor and legislature should make changes that would allow the Department of Revenue to report on the aggregate economic activity (including taxes paid and economic benefits) and number of permanent jobs (professional and janitorial) that are created by data centers.

    b. The Department of Revenue should be directed to prepare an analysis on the economic activity and jobs that result from the data center tax incentives compared to tax incentives for other activities.

    c. The governor and legislature should review whether the protections for the electrical grid, salmon and tribal resources, water, and consumers are sufficient and whether the data center tax incentives are in the public interest every two years and adjust these programs as necessary.

Attachment A: 2022 Energy Vision for the Columbia River Basin: Energy Efficiency and Development Recommendations

Summary

The CRITFC Energy Vision for the Columbia River Basin includes 43 recommendations that are designed to ensure that renewable resources in combination with increased storage, reductions in peak demand, and increased energy efficiency can provide clean, adequate, reliable, and affordable electricity, support the restoration of heathy, harvestable salmon populations, and prevent future damage to salmon and steelhead and other tribal resources caused by the electrical system. For more information see www.critfc.org/energy-vision. The recommendations address these nine major activities.

Improve River Configuration and Operations: The region needs to plan for changes to reduce the damage to migrating salmon and steelhead caused by the Columbia Basin dams, including breaching the four lower Snake River dams.

Amend the Columbia River Treaty: Amend the treaty to include protections for fish and wildlife and expand the scope to include win-win opportunities to integrate renewable resources.

Reduce Peak Loads: The Energy Vision details actions to reduce peak demands that can save salmon and money.

Maximize Energy Efficiency: Maintain and expand energy efficiency targets and work to exceed them. Energy efficiency measures are positive for fish and wildlife.

Harness Renewable Resources: Renewable resources in combination with storage and electric load management can create an environment that is better for fish and wildlife and other tribal resources.

Strategically Site Renewable Resources: Develop a regional plan for where renewable resources should be developed, and where they should not, and to provide expeditious siting with clear and uniform standards across all political subdivisions.

Increase Resource Adequacy: Electricity shortages have reduced protections and funding for fish and wildlife; Section 3 details actions to improve this problem.

Minimize Transmission and Distribution Systems: Load management, energy efficiency, and strategic siting of resources will reduce costs for consumers and the damage to tribal resources.

Address the Climate Crisis: Reduce greenhouse gas pollution and continue to increase energy efficiency to try to avoid the devastating effects we are facing.

CRITFC Energy Vision Recommendations

The Energy Vision for the Columbia River Basin includes detailed findings, rationales, and recommendations that are available at www.critfc.org/energy-vision. This section summarizes the relevant recommendations.

Reduce Peak Loads

Recommendation 4: The Council, BPA, and utilities should include the peak savings and reductions in transmission and distribution benefits in calculating the capacity value of energy efficiency programs.

Recommendation 5: Northwest public utility commissions should implement time-of-use rates to send an appropriate price signal that captures the dramatically different costs of using electricity during different times of the day.

Recommendation 6: Utilities should use demand response to manage system loads, reducing peak loads, ensuring reliability by encouraging customers to reduce demand during peak periods or shift loads from peak to off-peak hours.

Recommendation 7: Automobile manufactures should include systems that allow electric vehicles to schedule charging during off-peak periods.

Recommendation 8: Utilities should integrate electric vehicle charging and batteries into the power system to reduce costs to consumers and the power system and improve salmon migration.

Recommendation 9: BPA and utilities should work to improve the efficiency of electric vehicles.

Recommendation 10: The Council, BPA, and utilities should fund the incremental costs of heat pump water heaters to stimulate the adoption of this technology.

Recommendation 11: Utilities and BPA should develop and fund programs to schedule when water heaters operate.

Increase Electricity Storage

Recommendation 12: BPA and utilities should implement utility-scale battery projects.

Recommendation 13: BPA and utilities should implement incentive programs to expand the use of on-site batteries.

Recommendation 14: BPA and utilities should fund programs to reduce peak loads using the thermal mass of buildings.

Recommendation 15: The Council and utilities should not pursue potential pumped storage sites unless they are consistent with the siting criteria described in Section 3.6.

Recommendation 16: Utilities and the Council should continue to monitor green hydrogen technologies.

Maximize Energy Efficiency

Recommendation 17: The Council should increase the conservation targets in the 8th Power Plan to maintain at least the level of activity called for in the 7th Plan and work with BPA and utilities to try to exceed the targets.

Recommendation 18: The Council should monitor the implementation of energy efficiency programs to ensure that utilities meet the conservation targets.

Recommendation 19: All tribal homes and businesses should be fully weatherized by 2025 and all tribal homes and businesses should receive solar panels and battery systems that provide zero net energy by 2030.

Recommendation 20: Utilities should weatherize and achieve net zero energy for all low-income homes by 2035.

Recommendation 21: Utilities, the Northwest Energy Efficiency Alliance, and other organizations should implement comprehensive programs to improve energy management practices in the commercial and industrial sectors.

Harness Renewable Resources & Integrate/Synergize with Electricity Storage

Recommendation 22: Congress, state legislatures, the Council, and public utility commissions should review programs to reduce greenhouse gases to avoid unintended consequences.

Recommendation 23: The Council should analyze the integration of renewable resources under a range of scenarios for river operations.

Recommendation 24: Utilities and BPA should continue to pursue wind, and the associated efforts to integrate wind power, consistent with the tribal concerns and protections for fish, wildlife, and cultural resources.

Recommendation 25: The region should expand its efforts to promote utility-scale solar energy.

Recommendation 26: BPA and utilities should fund proof of concept projects for dual use solar.

Recommendation 27: States, local governments, and utilities should expand policies to promote on-site solar systems.

Recommendation 28: The Council, Northwest legislatures, energy regulators, and utilities should consider adopting zero net energy building standards.

Recommendation 29: State and local governments should adjust building codes to ensure that they can accommodate on-site batteries.

Recommendation 30: The Council, BPA, and utilities should continue to monitor and support other promising renewable resources.

Strategically Site Renewable Resources

Recommendation 31: CRITFC and its member tribes should work with state energy and siting agencies, federal agencies, Northwest Grid, the Northwest Power Pool, and others to develop a comprehensive plan for siting renewable resources and transmission lines that builds in efforts currently being developed in the states.

Increase Resource Adequacy

Recommendation 32: The Northwest Power Pool Resource Adequacy Program should address fish and wildlife protections by increasing electric system reliability while minimizing pressure on the existing hydroelectric system as the *de facto* fallback. In the near term, these reserves are likely to require having combustion turbines on standby. There may be opportunities to fuel these plants with biofuels that reduce their net carbon footprint. While CRITFC strongly supports the long-term elimination of all fossil fuels to address the climate crisis, in the near term, there may be circumstances where the choice is burning some natural gas or shutting down river operations and killing migrating salmon. CRITFC supports rate treatment for the costs associated with maintaining, staffing, fuel contracts and fuel storage, and other costs for these resources.

Recommendation 33: The California Public Utilities Commission and the California Independent System Operator should address reliability issues in California that could affect the Northwest.

Recommendation 34: BPA and Congress should address repayments to the Treasury to avoid curtailment of fish and wildlife protections.

Recommendation 35: The Pacific Northwest utilities, states, and federal agencies should closely monitor West Coast energy market developments to ensure that they address impacts on Columbia Basin Fish and Wildlife and other tribal resources.

Attachment B: Statutory References

Northwest Power Act Provisions

The Northwest Power Act of 1980 (Public Law 96-501, 16 USC 839) defines a new large single load as anything over 10 average megawatts for any 12-month consecutive period. NLSL must be served by BPA's new resources pool of resources—more expensive than the low-cost power pool that comes from the federal dams.

Section 3 of the Act's provision states:

> 3(13). "New large single load" means any load associated with a new facility, an existing facility, or an expansion of an existing facility–
>
> 3(13)(A). which is not contracted for, or committed to, as determined by the Administrator, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and [Northwest Power Act, §3(13)(A), 94 Stat. 2699-2700.]
>
> 3(13)(B). which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period. [Northwest Power Act, §3(13)(B), 94 Stat. 2700.]

Under Section 5, BPA is authorized to purchase power;

> 5(c)(7). The "average system cost" for electric power sold to the Administrator under this subsection shall be determined by the Administrator on the basis of a methodology developed for this purpose in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region. Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission. Such average system cost shall not include–
>
> > 5(c)(7)(A). the cost of additional resources in an amount sufficient to serve any new large single load of the utility; [Northwest Power Act, §5(c)(7)(A), 94 Stat. 2714.]
> >
> > 5(c)(7)(B). the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and [Northwest Power Act, §5(c)(7)(B), 94 Stat. 2714.]
> >
> > 5(c)(7)(C). any costs of any generating facility which is terminated prior to initial commercial operation. [Northwest Power Act, §5(c)(7)(C), 94 Stat. 2714.]

Northwest Power Act prohibits new direct service customers: Section 5(d)(2). The Administrator shall not sell electric power, including reserves, directly to new direct service industrial customers. [Northwest Power Act, §5(d)(2), 94 Stat. 2714.]

5(d)(4)(B). The term "new direct service industrial customer" means any industrial entity other than an existing direct service industrial customer. [Northwest Power Act, §5(d)(4)(B), 94 Stat. 2715.]

The NWPA has several provisions relating to rate design:

> 9(j). Retail rate designs which encourage conservation and efficient use of electric energy, installation of consumer-owned renewable resources, and rate research and development
>
> > 9(j)(1). The Council, as soon as practicable after December 5, 1980, shall prepare, in consultation with the Administrator, the customers, appropriate State regulatory bodies, and the public, a report and shall make recommendations with respect to the various retail rate designs which will encourage conservation and efficient use of electric energy and the installation of consumer-owned renewable resources on a cost-effective basis, as well as areas for research and development for possible application to retail utility rates within the region. Studies undertaken pursuant to this subsection shall not affect the responsibilities of any customer or the Administrator which may exist under the Public Utility Regulatory Policies Act of 1978. [Northwest Power Act, §9(j)(1), 94 Stat. 2734.]
>
> > 9(j)(2). Upon request, and solely on behalf of customers so requesting, the Administrator is authorized to (A) provide assistance in analyzing and developing retail rate structures that will encourage cost-effective conservation and the installation of cost-effective consumer-owned renewable resources; (B) provide estimates of the probable power savings and the probable amount of billing credits under section 839d(h) of this title that might be realized by such customers as a result of adopting and implementing such retail rate structures; and (C) solicit additional information and analytical assistance from appropriate State regulatory bodies and the Administrator's other customers. [Northwest Power Act, §9(j)(2), 94 Stat. 2734.]

Washington Statutory Provisions on Rate Equality

Public-Owned Utilities

RCW 54.16.040
Electric energy.
A district may purchase, within or without its limits, electric current for sale and distribution within or without its limits, and construct, condemn and purchase, purchase, acquire, add to, maintain, conduct, and operate works, plants, transmission and distribution lines and facilities for generating electric current, operated either by water power, steam, or other methods, within or without its limits, for the purpose of furnishing the district, and the inhabitants thereof and any other persons, including public and private corporations, within or without its limits, with electric

current for all uses, with full and exclusive authority to sell and regulate and control the use, distribution, rates, service, charges, and price thereof, free from the jurisdiction and control of the utilities and transportation commission, in all things, together with the right to purchase, handle, sell, or lease motors, lamps, transformers and all other kinds of equipment and accessories necessary and convenient for the use, distribution, and sale thereof: PROVIDED, That the commission shall not supply water to a privately owned utility for the production of electric energy, but may supply, directly or indirectly, to an instrumentality of the United States government or any publicly or privately owned public utilities which sell electric energy or water to the public, any amount of electric energy or water under its control, and contracts therefor shall extend over such period of years and contain such terms and conditions for the sale thereof as the commission of the district shall elect; such contract shall only be made pursuant to a resolution of the commission authorizing such contract, which resolution shall be introduced at a meeting of the commission at least ten days prior to the date of the adoption of the resolution: PROVIDED FURTHER, That it shall first make adequate provision for the needs of the district, both actual and prospective.

Investor-Owned Utilities

RCW 80.28.100 - Rate discrimination prohibited—Exception.
No gas company, electrical company, wastewater company, or water company may, directly or indirectly, or by any special rate, rebate, drawback or other device or method, charge, demand, collect or receive from any person or corporation a greater or less compensation for gas, electricity, wastewater company services, or water, or for any service rendered or to be rendered, or in connection therewith, except as authorized in this chapter, than it charges, demands, collects or receives from any other person or corporation for doing a like or contemporaneous service with respect thereto under the same or substantially similar circumstances or conditions.

RCW 80.28.090
Unreasonable preference prohibited.
No gas company, electrical company, wastewater company, or water company may make or grant any undue or unreasonable preference or advantage to any person, corporation, or locality, or to any particular description of service in any respect whatsoever, or subject any particular person, corporation or locality or any particular description of service to any undue or unreasonable prejudice or disadvantage in any respect whatsoever.
Washington Statute Regarding Obligations of Public Owned Utility on Provision of Water

RCW 54.16.030
Water and irrigation works.
A district may construct, purchase, condemn and purchase, acquire, add to, maintain, conduct, and operate waterworks and irrigation plants and systems, within or without its limits, for the purpose of furnishing the district, and the inhabitants thereof, and of the county in which the district is located, and any other persons including public and private corporations within or without the limits of the district or the county, with an ample supply of water for all purposes, public and private, including water power, domestic use, and irrigation, with full and exclusive authority to sell and regulate and control the use, distribution, and price thereof.
Emphasis added to all statutes cited above

Oregon Statutory Provisions

Oregon POWER Act (HB3546, 2025) - New customer rate class for data centers and cryptocurrency within Oregon's investor-owned utilities

OR HB3409 (2023). Sections 8& 9 address commercial building energy efficiency standards. Building Energy Performance Standard are codified as Oregon Revised Statutes (ORS) 469.275 - 469.291

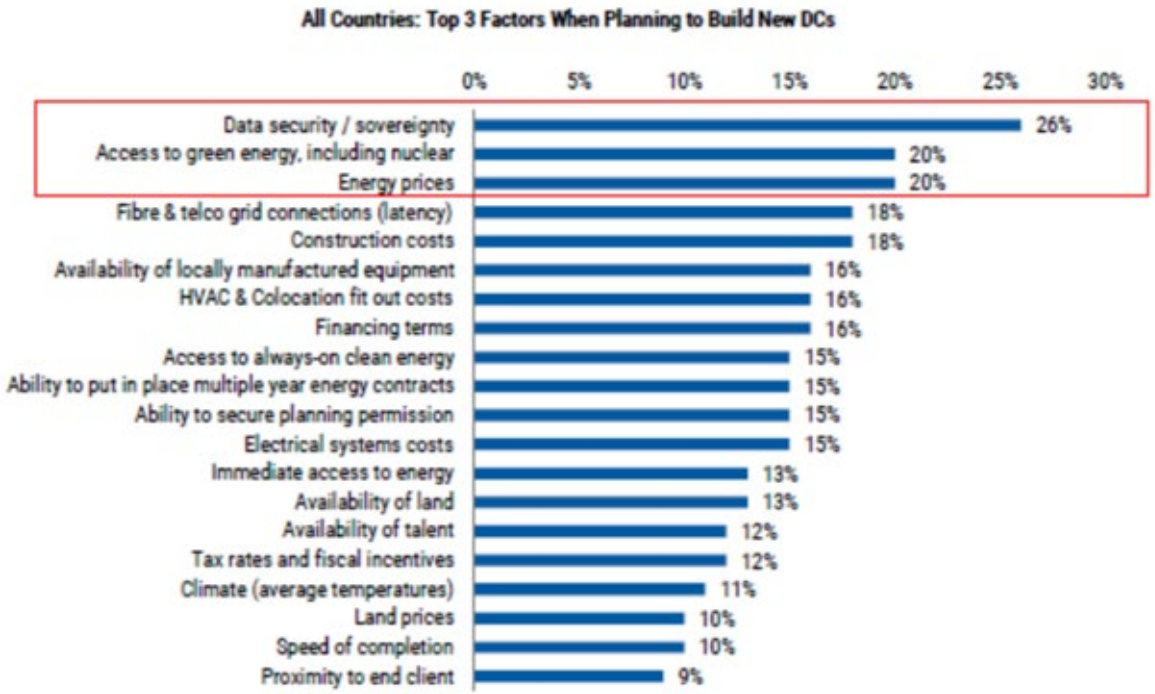
Attachment C: Factors Affecting Decisions on Location and the Profitability of Data Centers

Decisions on where to locate data centers. The key factors in the United States were:

1. data security,
2. energy prices,
3. access to energy,
4. and speed to completion are the most important factors.

A report by Morgan Stanley Research showed that tax incentives were 16th on the list of factors when planning to build data centers[1].

Exhibit 8: Top 3 factors when planning on building DCs (US, UK, Italy, Spain and Norway)



The Exhibit above is based on two surveys that were conducted for Morgan Stanley by AlphaWise in March 2025. The first was based on 239 interviews with senior procurement and sourcing decision makers for data center operators. The second survey interviewed 234 senior sources decision makers at data center builders and suppliers.

[1] *Global Data Center Capacity Growth to Increase 6x*, Morgan Stanley Research, page 7.

Survey Details

Primary Research

See what others don't.

1) Data security/sovereignty, access to green energy and energy prices are the most important considerations for operators when building new DCs. Over the next 2 years, operators believe the main bottlenecks will be: securing primary or back up power generation, availability of chips/GPUs and speed of access to electricity. 2) Capacity has increased by an average of 5% over the last 12 months and could increase by 9% in the next 2 years. In the next 2 years, 34% of operators say they will invest more in the US, followed by the UK (29%), Spain (27%), Italy (26%) and France (23%). 3) In the next 2 years, operators believe that total DC costs will increase by an average of 11.48%, with electrical systems most responsible for total DC cost increases, followed by cooling technology and grid connection. For builders & suppliers, DC related building & supply costs are expected to increase by an average of 14% in the next 2 years.

Methodology

In March 2025, we carried out 2 surveys (with a total sample size of 473) to understand DC expansion over the next 2 years in the US and Europe.

DC Operator Survey

We carried out a total of 239 online interviews with senior procurement & sourcing decision makers at data center operators.

Sample size by country: US: 52, UK: 54, Italy: 52, Spain: 52 & Norway: 29

Sample size by procurement responsibility: DC builders: 136, Construction materials: 96, Electrical systems: 122, HVAC/Mechanical systems: 133 & Colocation fit out: 89

DC Builders & Suppliers Survey

We carried out a total of 234 online interviews with senior sourcing decision makers at data center builders & suppliers for data center operators.

Sample size by country: US: 57, UK: 48, Italy: 48, Spain: 49 & Norway: 32

Sample size by supplier type: DC builders: 134, Construction materials: 118, Electrical systems: 134, HVAC/Mechanical systems: 129 & Colocation fit out: 77

Team behind the analysts.

AlphaWise Primary Research gathers alternative data and generates unique insights via an innovative analytical and visualization platform.

Source: AlphaWise

Economic importance of tax incentives: An analysis by TeraWulf showed potential illustrative business models for financing data centers. The summary appears to show that data centers could be very profitable. The margins (profits) range from 65 to 90 percent and the Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) range from valuation of 7 to 20 times EBITDA. Attachment B provides more detail on the factors affecting decisions on where to locate and the profitability of data centers.

Potential HPC Data Center Construction Financing Structures

WULF Compute – Potential Illustrative Business Models

Maximizing land, megawatts, and capital for optimal long-term value creation

WULF Compute's Core Business

	Cloud Service Provider (CSP)	Colocation – Whitespace & Rack Ready	Build to Suit
Description	Shell data center and GPU clusters; space, power, cooling, fiber/internet, security, compute, storage and environment.	Shell data center; lease rack ready whitespace including redundant power, cooling, fiber/internet, and security	Data center built to spec; lease space, redundant power, cooling, fiber/internet, and security
Customer	Multiple – Managed through cloud partner	Multiple – Enterprise and well funded startups	Single – Hyperscaler
Contract Size	0.1 – 50 MW	0.5 – 100 MW+	100+ MW
Contract Term	1 – 36 months	5 – 15 years	15+ years with renewals
O&M	WULF managed	WULF managed	Tenant managed
Build Cost per MW	$27 – 30 million (1)	$6 – 8 million (1)	$2 – 4 million (4)
Financing	Equity & Debt	Equity (initially)	Highly Bankable
Revenue per MW	$11 – 18 million (2)	$1.3 – 1.8 million (3)	$0.2 – 0.5 million
Margins	70 – 80%	65 – 75%	90% +
Valuation Range	7-12x EBITDA	10-15x EBITDA	15-20x EBITDA

TERAWULF

(1) Build cost for CSP and colocation model reflect liquid cooling infrastructure.
(2) Low end of range based on long-term reserve contract at $2.1/GPU/hr with 100% rental utilization, high end of range represents $4.50/GPU/hr of on-demand revenue at 80% rental utilization.
(3) Does not include customer pass-through energy expense. Subject to term length and payment terms.
(4) Based on air cooled powered shell infrastructure. NNN Rent Structure; customer pays all OpEx directly.

16

Source: TeraWulf.

Appendix E: Executive Order 25-05

STATE OF WASHINGTON
OFFICE OF GOVERNOR BOB FERGUSON

EXECUTIVE ORDER 25-05

DATA CENTER WORKGROUP

WHEREAS, data centers are critical infrastructure supporting Washington State's digital economy, providing essential services that drive innovation and economic growth; and

WHEREAS, the data center industry is highly competitive, with states offering various incentives to attract investments; and

WHEREAS, data centers consume significant amounts of electricity, which can put additional strain on the local power grid and can necessitate increased energy generation, storage, and transmission; and

WHEREAS, locating data centers in Washington State can lead to an increase in jobs and property tax revenue, particularly for rural communities; and

WHEREAS, the most recent analysis from the Joint Legislative Audit and Review Committee estimated that data center sales and use tax exemptions saved beneficiaries over $100 million in the 2017-2019 biennium; and

WHEREAS, balancing economic development, state and local tax revenue, energy use, and environmental responsibility is vital to ensuring Washington state remains a leader in both technology and sustainability;

NOW, THEREFORE, I, Bob Ferguson, Governor of the state of Washington, by the power vested in me by the Constitution and the statutes of the state of Washington, do hereby order and direct as follows:

1. The Department of Revenue shall establish and lead a Data Center Workgroup.
2. The Workgroup shall include representatives from the Department of Commerce, the Utilities and Transportation Commission, the Department of Ecology, electric utilities, environmental advocacy groups, labor organizations, industry stakeholders, and others, as designated by the Office of the Governor.
3. The Workgroup shall discuss the impacts of data centers on Washington State's economy, tax revenue, energy use, and the environment. The Workgroup will consider policies that balance industry growth, tax revenue needs, energy constraints, and sustainability.
4. By December 1, 2025, the Workgroup shall submit its findings and any policy recommendations to the Governor.

This Executive Order shall be implemented consistent with applicable law. Provisions of this Order are not intended to alter any existing collective bargaining agreements. This Order is not intended to confer and does not confer any legal right or entitlement and shall not be used as a basis for legal challenges to any rule or any other action or inaction of the governmental entities and employees subject to it.

This Order takes effect immediately.

Signed and sealed with the official seal of the state of Washington on this 3rd day of February AD, Two Thousand and Twenty-Five, at Olympia, Washington.

By

/s/
Bob Ferguson
Governor

BY THE GOVERNOR

/s/
Secretary of State

2

[1] Keith Swenson was appointed by the Department of Commerce to fill the vacancy created by Joseph Williams who was appointed the Acting Director of the State Broadband Office.

[2] Michael Mattmiller filled the vacancy created by Irene Plenefisch due to her retirement from Microsoft..

[3] RCW 70A.45.070

[4] Northwest Power and Conservation Council: 9th Power Plan Demand Forecast

[5] Current Power Market Trends and Implications for the Data Center Industry; Large-scale Transmission Deployment Saves Consumers Money

[6] 2024 United States Data Center Energy Usage Report | Energy Technologies Area; Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption; AI's energy impact is still small—but how we handle it is huge; Get A Load of This: Regulatory solutions to enable better forecasting of large loads

[7] Northwest Power and Conservation Council: 9th Power Plan Demand Forecast

[8] The Energy & Water Use Impacts of Building System Design for Data Centers

[9] Load Growth Is Here to Stay, but Are Data Centers? - E3; Current Power Market Trends and Implications for the Data Center Industry; Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption

[10] 2024 United States Data Center Energy Usage Report | Energy Technologies Area; Load Growth Is Here to Stay, but Are Data Centers? - E3; Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections; Get A Load of This: Regulatory Solutions to Enable Better Forecasting of Large Loads

[11] Byte Blackouts: How large data center loads are surfacing new issues; Big Tech's data center boom poses new risk to US grid operators | Reuters; Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems; Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power;

[12] Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power; Virginia Data Center Study: Electric Infrastructure and Customer Rate Impacts; The Energy Demands of the Data-Driven Future: Challenges and Solutions

[13] Load Growth – What States Are Doing to Accommodate Increasing Electric Demand; Database of Emerging Large-Load Tariffs; Get A Load of This: Regulatory solutions to enable better forecasting of large loads; Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power; National Caucus of Environmental Legislators: Data Centers Brief

[14] Load Growth: What States Are Doing to Accommodate Increasing Electric Demand; Database of Emerging Large-Load Tariffs (DELTa)

[15] Breaking Barriers to Data Center Growth; Clean Energy Resources to Meet Data Center Electricity Demand; A Climate Hawk's Guide to Northwest Data Centers

[16] Breaking Barriers to Data Center Growth; Clean Energy Resources to Meet Data Center Electricity Demand; A Climate Hawk's Guide to Northwest Data Centers

[17] "In October 2024, Amazon signed a deal with Energy Northwest, a utility in Washington state, that will see Amazon fund the initial phase of a planned X-energy small modular reactor project in the state. The tech giant will have a right to buy electricity from one of the modules in the first project, which could generate 320 megawatts of electricity and be expanded to generate as much as 960 megawatts. Many new AI-focused data centers under construction will require 500 megawatts of power or more, so this project might be just large enough to power a single site." Can Nuclear Power Really Fuel the Rise of AI?

[18] Diesel pollution from data centers

[19] ProPublica Article, March 12 2025

[20] https://blogs.microsoft.com/blog/2020/01/16/microsoft-will-be-carbon-negative-by-2030/

[21] Matthew Fox, Principal Corporate Counsel with Microsoft filled the vacancy caused by Irene Plenefish's retirement on the Energy & Resource Impacts Subgroup. (Michael Mattmiller filled the vacancy in the meetings of the full Workgroup.)